

## REPORT DOCUMENTATION PAGE

Form Approved  
OMB No. 0704-0188

Public reporting burden for this collection of information is estimated to average 1 hour per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to Washington Headquarters Services, Directorate for Information Operations and Reports, 1215 Jefferson Davis Highway, Suite 1204, Arlington, VA 22202-4302, and to the Office of Management and Budget, Paperwork Reduction Project (0704-0188), Washington, DC 20503.

1. AGENCY USE ONLY (Leave blank)	2. REPORT DATE	3. REPORT TYPE AND DATES COVERED
	22.Aug.00	THESIS
4. TITLE AND SUBTITLE THE EFFECT OF TRANSMISSION ON A DOMINANT FIRM'S ABILITY TO EXERT MARKET POWER IN THE ELECTRICITY GENERATION INDUSTRY		5. FUNDING NUMBERS
6. AUTHOR(S) CAPT QUICK DAVID M		
7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES) COLORADO SCHOOL OF MINES		8. PERFORMING ORGANIZATION REPORT NUMBER  CY00358
9. SPONSORING/MONITORING AGENCY NAME(S) AND ADDRESS(ES) THE DEPARTMENT OF THE AIR FORCE AFIT/CIA, BLDG 125 2950 P STREET WPAFB OH 45433		10. SPONSORING/MONITORING AGENCY REPORT NUMBER
11. SUPPLEMENTARY NOTES		
12a. DISTRIBUTION AVAILABILITY STATEMENT Unlimited distribution In Accordance With AFI 35-205/AFIT Sup 1		12b. DISTRIBUTION CODE
13. ABSTRACT (Maximum 200 words)		

**DISTRIBUTION STATEMENT A**  
Approved for Public Release  
Distribution Unlimited

14. SUBJECT TERMS		15. NUMBER OF PAGES	
		16. PRICE CODE	
17. SECURITY CLASSIFICATION OF REPORT	18. SECURITY CLASSIFICATION OF THIS PAGE	19. SECURITY CLASSIFICATION OF ABSTRACT	20. LIMITATION OF ABSTRACT

THE EFFECT OF TRANSMISSION ON A DOMINANT FIRM'S ABILITY  
TO EXERT MARKET POWER IN THE ELECTRICITY  
GENERATION INDUSTRY

Captain David M. Quick  
AFIT/CIGG  
Colorado School of Mines  
daquick@flash.net

ABSTRACT

This research addresses the effect that transmission capacity between regions has on a dominant firm's ability to exert horizontal market power in a restructured electricity generation market. An algorithm that determines a dominant firm's optimal dispatch strategy is developed to analyze the effect of transmission. This algorithm iteratively solves a linear programming model to approximate the non-linear profit maximization problem for a dominant firm. The algorithm is applied to Colorado to test previous theoretical research on the effect of transmission on market power and to provide estimates of potential market power in a restructured Colorado electricity industry. Potential mitigation strategies such as expanding the transmission grid, divesting generation assets of the dominant firm, promoting entry into the market, and limiting capacity withholding by the dominant firm are also examined.

Using the year 2005, this research shows that Public Service Company of Colorado (PSCo), the dominant generation firm in Colorado, could act as a monopolist facing an inelastic demand and dictate a maximum price 54.9% of the time in a restructured electricity generation market. For the remaining periods of demand, PSCo could force an 11.6% average markup over the perfect competition price. The research demonstrates that without changes to the structure of the industry, PSCo will have significant market power in the short-run dispatch of generation. With the right action by policy makers, the potential for market power in Colorado can be reduced significantly, if not eliminated. Adding 1,000 megawatts (MW) of transmission capacity into eastern Colorado reduces the percentage of time PSCo gets a maximum markup from 54.9% to 11.7% and lowers the average markup for other periods from 11.6% to 6.4%. Similarly, a scenario divesting 25% of PSCo's generation assets lowers the percentage of time with the maximum markup to 11.7% and the average markup for other periods to 1.8%. Both of these scenarios significantly reduce the percentage of time the market faces maximum markups because of PSCo's strategic behavior and reduce average markups for the other periods close to or below the 5% guideline used by the Department of Justice and Federal Trade Commission in their analysis of competition in markets.

## REFERENCES CITED

Andersson, Bo and Lars Bergman. 1995. Market Structure and the Price of Electricity: An Ex Ante Analysis of the Deregulated Swedish Electricity Market. *The Energy Journal* 16, no. 2: 97-109.

Bailey, Elizabeth M. 1998. *The Geographic Expanse of the Market for Wholesale Electricity*. MIT Center for Energy and Environmental Policy Research.

Bakeman, Steven, Stephen Rassenti, and Vernon Smith. 1997. *Efficiency and Income Shares in High Demand Energy Networks: Who Receives the Congestion Rents When a Line Is Constrained?* University of Arizona: Economic Science Laboratory.

Bayless, Charles E. 1994. Less is More: Why Gas Turbines Will Transform Electric Utilities. *Public Utilities Fortnightly* 132 (December 1): 21-25.

Behling, B. N. 1938. *Competition and Monopoly in Public Utility Industries*. Urbana: University of Illinois Press.

Biewald, Bruce, Heidi Croll, and Richard Rosen. 1996. *Potential Costs and Benefits of Electric Industry Restructuring*. Boston: Tellus Institute.

Bishop, Christopher M. 1995. *Neural Networks for Pattern Recognition*. Oxford: Oxford University Press.

Borenstein, Severin and James Bushnell. 1999. An Empirical Analysis of the Potential for Market Power in California's Electricity Industry. *Journal of Industrial Economics* 47, no. 3: 285-323.

Borenstein, Severin, James Bushnell, and Christopher Knittel. 1999. Market Power in Electricity Markets: Beyond Concentration Measures. *Energy Journal* 20, no. 4: 65-88.

Borenstein, Severin, James Bushnell, and Steven Stoft. 1998. The Competitive Effects of Transmission Capacity in a Deregulated Electricity Market. *Rand Journal of Economics*. Forthcoming.

Borenstein, Severin, James Bushnell, and Frank Wolak. 1999. *Diagnosing Market Power in California's Deregulated Wholesale Electricity Market*. POWER Working Paper PWP-064. University of California Energy Institute.

Bradley, P.S. and Usama M. Fayyad. 1998. Refining Initial Points for K-Means Clustering. In *Fifteenth International Conference on Machine Learning*. Madison, Wisconsin: Morgan Kaufmann Publishers.

Bushnell, James. 1998. *Water and Power: Hydroelectric Resources in the Era of Competition in the Western U.S.* POWER Working Paper PWP-056. University of California Energy Institute.

Cardell, Judith B., Carrie Cullen Hitt, and William W. Hogan. 1997. Market power and Strategic Interaction in Electricity Networks. *Resource and Energy Economics* 19: 109-137.

Chao, Hung-po and Stephen Peck. 1996. A Market Mechanism for Electric Power Transmission. *Journal of Regulatory Economics* 10: 25-59.

Cicchetti, Charles J. and Colin M. Long. 1999. Transmission Products and Pricing: Hidden Agendas in the ISO/Transco Debate. *Public Utilities Fortnightly* 137, no. 12: 33-45.

Colorado Air Quality Control Commission. 1999. *Colorado Air Quality Control Commission: Report to the Public 1998-1999*. Denver: Colorado Department of Public Health and Environment.

Colorado Electricity Advisory Panel. 1999. *Evaluation Study Report*. Denver: Colorado Public Utilities Commission.

Colorado Office of Consumer Counsel. 1999. *Comments of the OCC to the Colorado Electricity Advisory Panel on Market Power: The Potential Exercise of Horizontal Market Power in a Deregulated Colorado Electricity Market*. Denver: Colorado's Office of Consumer Counsel.

Colorado Public Utilities Commission. 2000. Decision No. C00-190, Docket No. 99A-549E. Denver: State of Colorado.

Deb, Rajat, Richard Albert, and Lie-Long Hsue. 1996. *Modeling Competitive Energy Market in California: Analysis of Restructuring*. Los Altos, Calif: LCG Consulting.

Energy Information Administration (EIA). 1996a. *Annual Energy Outlook 1997*. Washington, D.C.: U.S. Department of Energy.

\_\_\_\_\_. 1996b. *Electric Power Annual, Volume I*. Washington, D.C.: U.S. Department of Energy.

\_\_\_\_\_. 1998a. *The Changing Structure of the Electric Power Industry: Selected Issues, 1998*. Washington, D.C.: U.S. Department of Energy.

\_\_\_\_\_. 1998b. *Electric Power Annual, Volume I*. Washington, D.C.: U.S. Department of Energy.

\_\_\_\_\_. 2000. *Status of State Electric Utility Deregulation Activity*. Washington, D.C.: U.S. Department of Energy.

Federal Energy Regulatory Commission (FERC). 1981. *Power Pooling in the United States*. Washington, DC: Office of Electric Power Regulation.

\_\_\_\_\_. 1996. ORDER NO. 888, Docket No. RM95-8-000 and RM94-7-001. Washington, DC.

\_\_\_\_\_. 1999. Docket No. RM99-2-000, Regional Transmission Organizations. Washington, DC.

Feiler, Thomas, Karl R. Rabago, and Katherine Wang. 1999. *Socio-Economic and Legal Issues Related to an Evaluation of the Regulatory Structure of the Retail Electric Industry in the State of Colorado*. Econergy International Corporation.

Fox-Penner, Peter. 1998. *Electric Utility Restructuring: A Guide to the Competitive Era*. Vienna, Virginia: Public Utilities Reports, Inc.

Graves, Frank C., E. Grant Read, Philip Q. Hanser, and Robert L. Earle. 1998. One-Part Markets for Electric Power: Ensuring the Benefits of Competition. In *Power Systems Restructuring: Engineering and Economics*, ed. Marija Ilic, Francisco Galiana, and Lester Fink. Boston: Kluwer Academic Publishers.

Gray, H. M. 1940. The Passing of the Public Utility Concept. *Journal of Land and Public Utility Economics* (February).

Green, Richard J. and David M. Newbery. 1992. Competition in the British Electricity Spot Market. *Journal of Political Economy* 100, no. 5: 929-953.

Hebert, Jr., Curt L. and Joshua Z. Rokach. 1999. The FERC-State Dialogue on Electric Transmission: Where We Go from Here. *Public Utilities Fortnightly* 137, no. 9: 24-31.

Hobbs, Benjamin F. 1986. Network Models of Spatial Oligopoly with an Application to Deregulation of Electricity Generation. *Operations Research* 34, no. 3 (May-June): 395-409.

Hogan, William H. 1993. Markets in Real Electric Networks Require Reactive Prices. *The Energy Journal* 14, no. 3: 171-200.

\_\_\_\_\_. 1997. A Market Power Model with Strategic Interaction in Electricity Networks. *The Energy Journal* 18, no. 4: 107-141.

\_\_\_\_\_. 1998. *Competitive Electricity Market Design: A Wholesale Primer*. Cambridge, MA: Center for Business and Government, John F. Kennedy School of Government, Harvard University.

Hogan, William H., Grant Read, and Brendan J. Ring. 1996. Using Mathematical Programming for Electricity Spot Pricing. *International Transactions in Operational Research* 3, no. 3/4: 209-221.

Joskow, Paul L. 1995. *Horizontal Market Power in Wholesale Power Markets*. Draft.

Joskow, Paul L. and Richard Schmalensee. 1983. *Markets for Power: An Analysis of Electric Utility Deregulation*. Cambridge, Massachusetts: The MIT Press.

Jurewitz, John L. and Robin J. Walther. 1997. Must-Run Generation: Can We Mix Regulation and Competition Successfully? *The Electricity Journal* 10, no. 10: 61-70.

Kahn, Edward, Shawn Bailey, and Luis Pando. 1997. Simulating Electricity Restructuring in California: Interactions with the Regional Market. *Resource and Energy Economics* 19: 3-28.

Klemperer, Paul D. and Margaret A. Meyer. 1989. Supply Function Equilibria in Oligopoly under Uncertainty. *Econometrica* 57, no. November: 1243-77.

Michaels, Robert J. 1999. ISO or Transco? It's not the Profit, But Who Gets the Reward. *Public Utilities Fortnightly* 137, no. 15: 52-54.

Oren, S. 1997. Economic Inefficiency of Passive Transmission Rights in Congested Electricity System with Competitive Generation. *The Energy Journal* 18, no. 1: 12-26.

PJM Interconnection, L.L.C. 1998. *PJM Open Access Transmission Tariff*.

Public Service Company of Colorado. 1999. *Draft 1999 Integrated Resource Plan*.

Read, E. Grant and Brendan J. Ring. 1995. A Dispatch Based Pricing Model for the New Zealand Electricity Market. *Transmission Pricing*. Forthcoming.

Rose, Kenneth. 1999. Testimony Before the U.S. House of Representatives Committee on Commerce Subcommittee on Energy and Power "Electricity Competition: Market Power, Mergers, and PUHCA." Washington, D.C.: The National Regulatory Research Institute.

Rosen, Richard A. and Heidi L. Kroll. 1996. *"Leveraging": The Key to the Exercise of Market Power in a POOLCO*. Boston: Tellus Institute.

Rudkevich, Aleksandr, Max Duckworth, and Richard Rosen. 1998. Modeling Electricity Pricing in a Deregulated Generation Industry: The Potential for Oligopoly Pricing in a Poolco. *The Energy Journal* 19, no. 3: 19-48.

Schmalensee, Richard and Bennett W. Golub. 1984. Estimating Effective Concentration in Deregulated Wholesale Electricity Markets. *Rand Journal of Economics* 15, no. 1: 12-26.

Skinner, Laurence E. 1999. RTOs by 2002? The Transmission Revolution Won't Be Quick. *Public Utilities Fortnightly* 137, no. 15: 59-66.

Stoft, Steven. 1997. *The Effect of the Transmission Grid on Market Power*. LBNL Report #40479. Ernest Orlando Lawrence Berkeley National Laboratory.

\_\_\_\_\_. 1999a. Financial Transmission Rights Meet Cournot: How TCCs Curb Market Power. *The Energy Journal* 20, no. 1: 1-23.

\_\_\_\_\_. 1999b. *Using Game Theory to Study Market Power in Simple Networks*. IAEE Tutorial on Game Theory Applications to Power Systems.

Stone and Webster Management Consultants, Inc. 1999. *Energy and Economic Modeling Issues Related to an Evaluation of the Regulatory Structure of the Retail Electric Industry in the State of Colorado*. Englewood, Colo.: Colorado's Electric Advisory Panel.

Sweetser, Al. 1998a. An Empirical Analysis of a Dominant Firm's Market Power in a Restructured Electricity Market: A Case Study of Colorado. PhD Dissertation, Colorado School of Mines, Golden, Colo.

\_\_\_\_\_. 1998b. Measuring Market Power in a State with a Dominant Supplier: A Case Study. *The Electricity Journal* (July): 61-70.

U.S. Department of Justice and Federal Trade Commission. 1992. Statement Accompanying Release of Revised Merger Guidelines.

Viscusi, W. Kip, John M. Vernon, and Joseph E. Harrington, Jr. 1998. *Economics of Regulation and Antitrust*. Cambridge, Massachusetts: The MIT Press.

Weiss, Jurgen. 1998a. *Congestion Rents and Oligopolistic Competition in Electricity Networks: An Experimental Investigation*. Cambridge, MA: Harvard Business School.

\_\_\_\_\_. 1998b. *Market Power Issues in the Restructuring of the Electricity Industry: An Experimental Investigation*. Cambridge, MA: Harvard Business School.

Werden, Gregory J. 1996. Identifying Market Power in Electric Generation. *Public Utilities Fortnightly* February 15: 16-21.

Western Systems Coordinating Council (WSCC). 1998. *WSCC Operating Reserve White Paper*.

Wolak, Frank A. and Robert H. Patrick. 1996. *The Impact of Market Rules and Market Structure on the Price Determination Process in the England and Wales Electricity Market*. Stanford University.

Wolfram, Catherine D. 1995. *Measuring Duopoly Power in the British Electricity Spot Market*. Cambridge, MA: MIT Department of Economics.

THE EFFECT OF TRANSMISSION ON A DOMINANT FIRM'S ABILITY  
TO EXERT MARKET POWER IN THE ELECTRICITY  
GENERATION INDUSTRY

by

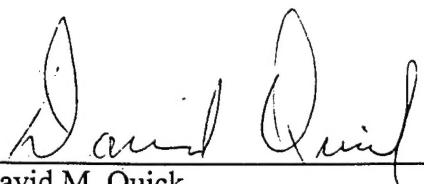
David M. Quick

A thesis submitted to the Faculty and the Board of Trustees of the Colorado  
School of Mines in partial fulfillment of the requirements for the degree of Doctor of  
Philosophy (Mineral Economics).

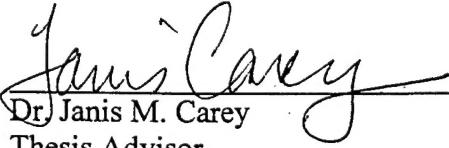
Golden, Colorado

Date 31 Mar 00

Signed:

  
David M. Quick

Approved:

  
Dr. Janis M. Carey  
Thesis Advisor

Golden, Colorado

Date 3/31/00

  
Dr. Roderick G. Eggert  
Director  
Division of Economics and Business

## ABSTRACT

This research addresses the effect that transmission capacity between regions has on a dominant firm's ability to exert horizontal market power in a restructured electricity generation market. An algorithm that determines a dominant firm's optimal dispatch strategy is developed to analyze the effect of transmission. This algorithm iteratively solves a linear programming model to approximate the non-linear profit maximization problem for a dominant firm. The algorithm is applied to Colorado to test previous theoretical research on the effect of transmission on market power and to provide estimates of potential market power in a restructured Colorado electricity industry. Potential mitigation strategies such as expanding the transmission grid, divesting generation assets of the dominant firm, promoting entry into the market, and limiting capacity withholding by the dominant firm are also examined.

Using the year 2005, this research shows that Public Service Company of Colorado (PSCo), the dominant generation firm in Colorado, could act as a monopolist facing an inelastic demand and dictate a maximum price 54.9% of the time in a restructured electricity generation market. For the remaining periods of demand, PSCo could force an 11.6% average markup over the perfect competition price. The research demonstrates that without changes to the structure of the industry, PSCo will have significant market power in the short-run dispatch of generation. With the right action by

policy makers, the potential for market power in Colorado can be reduced significantly, if not eliminated. Adding 1,000 megawatts (MW) of transmission capacity into eastern Colorado reduces the percentage of time PSCo gets a maximum markup from 54.9% to 11.7% and lowers the average markup for other periods from 11.6% to 6.4%. Similarly, a scenario divesting 25% of PSCo's generation assets lowers the percentage of time with the maximum markup to 11.7% and the average markup for other periods to 1.8%. Both of these scenarios significantly reduce the percentage of time the market faces maximum markups because of PSCo's strategic behavior and reduce average markups for the other periods close to or below the 5% guideline used by the Department of Justice and Federal Trade Commission in their analysis of competition in markets.

## TABLE OF CONTENTS

	Page
ABSTRACT.....	iii
TABLE OF CONTENTS.....	v
LIST OF FIGURES .....	viii
LIST OF TABLES.....	x
ACKNOWLEDGMENTS .....	xi
Chapter 1. INTRODUCTION.....	1
1.1 Motivation.....	1
1.2 General Problem .....	5
1.3 Specific Problem.....	6
1.4 Objectives .....	7
Chapter 2. THE ELECTRICITY INDUSTRY.....	9
2.1 Economic Dispatch of Generation.....	9
2.2 Competitive Electricity Markets .....	12
2.2.1 Bilateral Contracts.....	12
2.2.2 Power Pools.....	13
2.3 Transmission.....	15
2.3.1 Movement Toward Open Access Transmission.....	15
2.3.2 Transmission Pricing and Investment .....	18
Chapter 3. LITERATURE REVIEW.....	21
3.1 Market Power.....	21
3.2 Market Power Models in the Electricity Industry.....	25

	Page
3.2.1 Models Without Transmission Constraints .....	25
3.2.2 Models with Transmission Constraints .....	28
3.2.2.1 No Analysis of the Strategic Use of Transmission.....	28
3.2.2.2 Strategic Use of Transmission .....	37
Chapter 4. MODEL FORMULATION.....	40
4.1 Perfect Competition Model.....	40
4.2 Imperfect Competition Algorithm .....	49
4.2.1 Non-Linear Programming Model for Maximizing Profits .....	53
4.2.2 Profit Maximization Algorithm.....	54
Chapter 5. COLORADO'S ELECTRICITY INDUSTRY .....	59
5.1 Background .....	59
5.1.1 Location.....	60
5.1.2 Transmission .....	62
5.1.3 Demand .....	62
5.1.4 Supply.....	63
5.2 Data.....	64
5.2.1 Transmission Data.....	64
5.2.2 Supply Data .....	66
5.2.3 Demand Data.....	72
5.3 Application of the Algorithm to Colorado.....	74
Chapter 6. RESULTS.....	77
6.1 Market Power Analysis.....	77
6.1.1 Perfectly Competitive Results .....	77
6.1.2 Imperfect Competition Results.....	82
6.2 Effect of Transmission.....	90

	Page
Chapter 7. POLICY ANALYSIS .....	97
7.1 Increasing Transmission Capacity .....	97
7.2 Entry of New Generation .....	101
7.3 Divestiture .....	103
7.4 Limits to Capacity Withholding .....	106
7.5 Combined Strategies .....	108
Chapter 8. CONCLUSIONS AND RECOMMENDATIONS FOR FUTURE WORK .....	111
REFERENCES CITED.....	117
Appendix A. GAMS CODE .....	123
Appendix B. WSCC DATABASE .....	132

## LIST OF FIGURES

Figure	Page
1. Traditional Vertically Integrated Utility .....	1
2. Optimal Generation Plant Size for a Single Plant Based on Cost per Megawatt (MW), 1930-1990 .....	2
3. Short-Run Electricity Market.....	11
4. Transmission Effect in Two-Region Perfect Competition Example .....	42
5. Network Representation of Perfect Competition Model .....	44
6. Transmission Effect in Two-Region Imperfect Competition Example .....	51
7. Algorithm to Estimate a Dominant Firm's Market Power.....	57
8. WSCC and RMPA .....	61
9. WSCC Transmission Topology and Path Limits.....	65
10. Regional Supply Curve.....	71
11. 1996 RMPA Load Duration Curve .....	73
12. WSCC Perfect Competition Results for July 2005 Peak Demand .....	78
13. Transmission and ECO Prices for All Levels of Demand for Perfect Competition.....	79
14. WSCC Imperfect Competition Results for July 2005 Peak Demand .....	83
15. Transmission and ECO Prices for All Levels of Demand for Imperfect Competition .....	84
16. PSCo Production in Eastern Colorado.....	85

Figure	Page
17. Eastern Colorado Prices.....	86
18. ECO Prices at 72.7% of Peak Demand.....	92
19. Use vs. Capacity of the WCO-ECO Transmission Line.....	94

## LIST OF TABLES

Table	Page
1. Colorado's Distribution of Demand in 1995 .....	62
2. PSCo's 2005 Market Share in Colorado .....	68
3. Load Duration Curve Data.....	73
4. Comparison of Perfect Competition Prices.....	81
5. Imperfect Competition with Capacity Withholding .....	89
6. Comparison of Eastern Colorado Prices With and Without 1,000 MW of Added Transmission on WCO-ECO Line.....	91
7. Benefits from Additional Transmission into Eastern Colorado.....	99
8. Results for the Divestiture Scenarios.....	105
9. Results for Combined Scenarios.....	109

## ACKNOWLEDGMENTS

First, I want to express by sincere appreciation to my advisor, Dr. Janis Carey. Without her guidance, this research may not have been possible. Dr. Carey's oversight kept the research focused and her tireless effort immensely improved the final product.

I would also like to thank the other members of my dissertation committee, Dr. R. E. D. Woolsey, Dr. Robert Frost, Dr. Wade Martin, and Dr. William Navidi. A special thanks goes to Dr. Woolsey for teaching his unique perspective of the operations research career field. His crusade for applied operations research has been beneficial in this research and will pay dividends throughout my professional career.

The staff at the Colorado Public Utilities Commission (PUC) has also been paramount in the research effort, particularly Mr. Morey Wolfson and Dr. Gary Schmitz. Mr. Wolfson initiated my involvement at the PUC and went out of his way to ensure I had the resources necessary to perform my research. Dr. Schmitz's expertise on Colorado's electricity industry and the issues facing the industry proved invaluable.

Finally, and most importantly, I want to thank my incredible family. My loving wife, Angie, and two beautiful children, Heather and Cody, have been by my side throughout this journey and they are the ones that make it all worthwhile.

## Chapter 1

### INTRODUCTION

#### 1.1 Motivation

The changing environment in the electricity industry around the world raises many questions regarding its future structure. The production of electricity consists of three stages: generation, transmission, and distribution. Traditionally many electric utilities have integrated vertically to perform all three functions (see Figure 1).

Governments granted exclusive territories for electric utilities to serve and regulated the

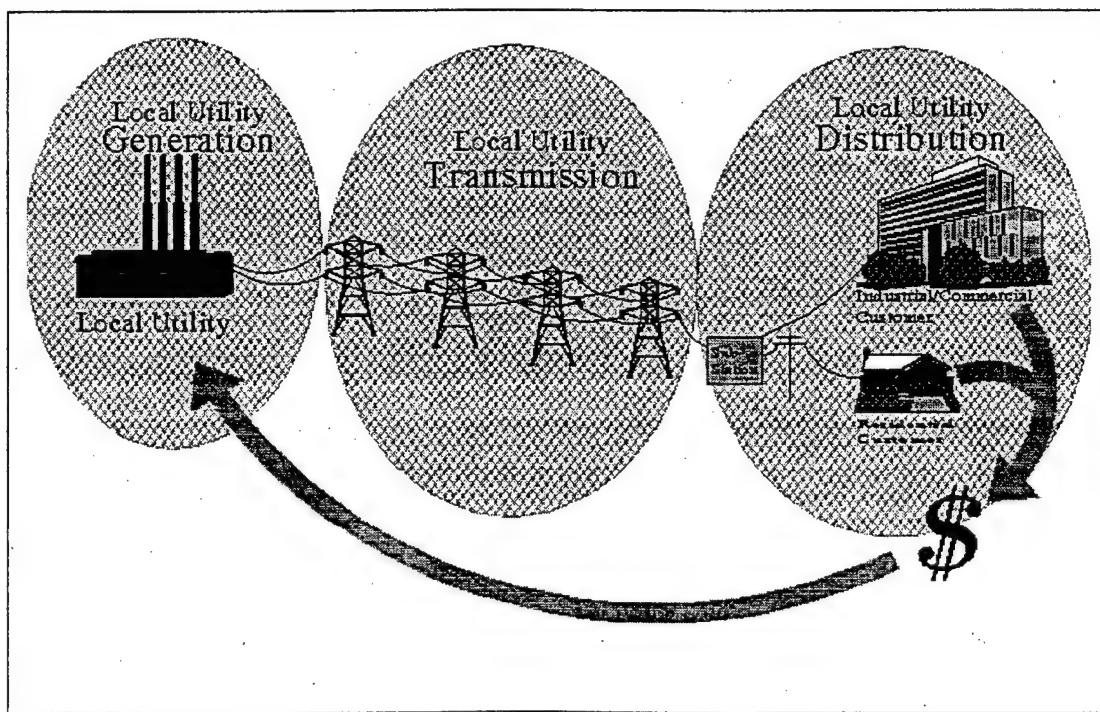


Figure 1. Traditional Vertically Integrated Utility

utilities under the assumption that they were natural monopolies, or that they experienced cost subadditivity across relevant output ranges. In return, each utility had an obligation to serve its territory. A few economists argued from the start that electric utilities were not natural monopolies (Behling 1938; Gray 1940). With the development of smaller, less expensive generation plants, many more economists now believe that generation firms are not natural monopolies and that generation will be more efficient with multiple suppliers in a region. Figure 2 shows that the average generation cost per megawatt at

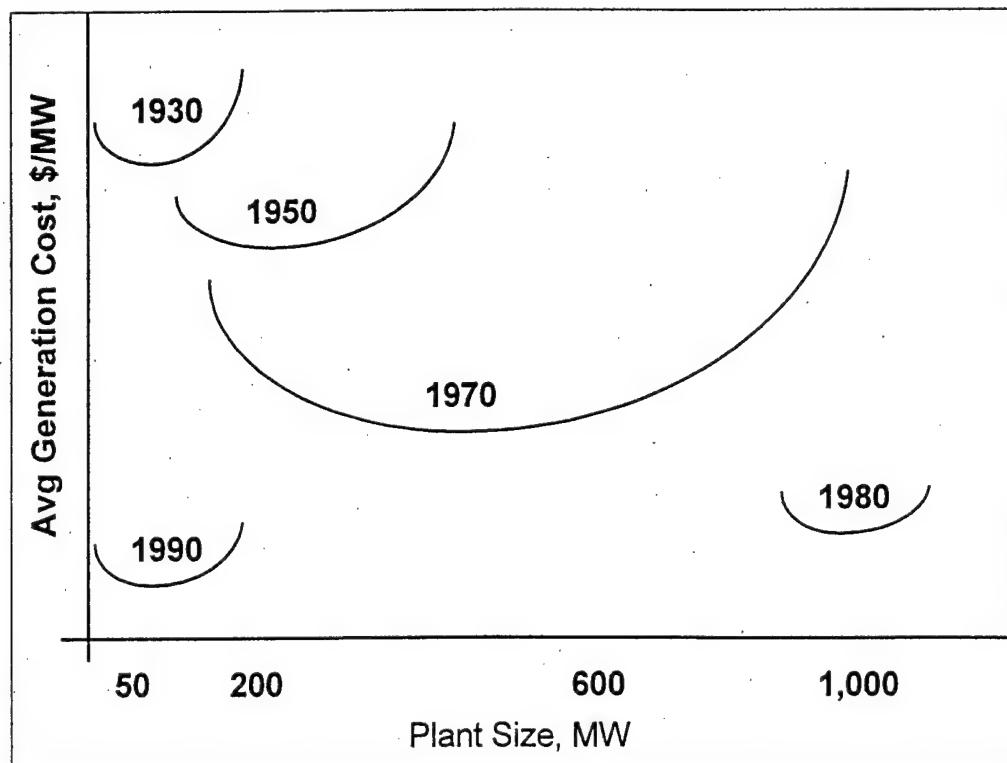


Figure 2. Optimal Generation Plant Size for a Single Plant Based on Cost per Megawatt (MW), 1930-1990

Source: Bayless 1994

the plant level has steadily declined for the past 70 years. Up until the 1980s, plant sizes increased significantly. With the dramatic decrease in plant size in the past decade, however, new plants are smaller and cheaper than at any other time in history. These changes in generation technology, in addition to changes in information technology and to price disparity between different regions and customer groups, are primary factors driving the movement to restructure the electricity industry and allow competition in generation. Restructuring will also affect the transmission and distribution of electricity, but these stages of production still have natural monopoly characteristics and are not being opened to competition.

Proponents of restructuring claim that deregulation of electricity generation and an increased reliance upon market forces will lead to a more efficient electric utility industry. Skeptics argue that this claim has not been supported with sound analysis (Biewald, Croll, and Rosen 1996). Even if the efficiencies suggested by the proponents exist, the ability of incumbent firms to exercise market power may still stand as an obstacle to restructuring in many regions. One way an incumbent firm can exercise market power is through the vertical integration of its resources in the three production stages. However, the industry is moving toward separate ownership or control of these different stages and the distribution and transmission of electricity should remain regulated in restructured electricity markets, so vertical market power should not be a significant obstacle. On the other hand, horizontal market power, or the ability of a firm to exercise market power in a single production stage, may be a primary hurdle for some

regions looking to restructure because of the exclusive franchises given to generation firms under the regulated regime. Transmission can introduce competition for an incumbent firm by allowing entry into the market. Once transmission lines are congested, however, barriers to entry provide incumbent firms an opportunity to exercise horizontal market power.

Franchise areas define territories in which one utility has exclusive rights to sell all retail power (Fox-Penner 1998). Regulation has limited the ability of the utilities to earn monopoly profits in their given franchise areas. When restructured, however, the ability to exert horizontal market power in generation will no longer be limited by regulation. In addition to concentration issues, electricity generation is also prone to the exercise of horizontal market power because of expensive or nonexistent storage, capital-intensive transport, and relatively price-inelastic demand (Rudkevich, Duckworth, and Rosen 1998). Depending on the size of the franchise area, the capacity of competing firms in the surrounding regions, and the adequacy of transmission to allow competition among regions, horizontal market power in generation may be a serious problem for some regions looking to restructure their electricity industry.

Although there is a push to restructure the electricity industry from the federal government, most restructuring activity in the United States is taking place at the state level. Currently, 21 states have begun restructuring, 3 have issued comprehensive regulatory orders, and 26 states (plus the District of Columbia) are in the process of conducting studies to determine whether they should restructure (EIA 2000).

Considerable research has been performed on market power in the electricity industry. Only a few of these studies address the important role transmission plays in defining market boundaries and determining market power despite the fact that the transmission network is an integral element in achieving an efficient electricity industry. Read and Ring (1995) define the role of the transmission network as providing the infrastructure to support a competitive electricity market. They also discuss how transmission is used to balance regional generation cost differences. While the transmission network may enhance competition, congestion on the network may segregate markets and limit competition. Firms may have an incentive to dispatch their generating units strategically to congest the network and limit competition in a region. Research has shown the relationship between transmission and different market structures, but a model that determines the optimal dispatch strategy of a dominant firm has not been developed and applied to a regional electricity market.

## 1.2 General Problem

This research addresses the effect that transmission capacity between regions has on a dominant firm's ability to exert horizontal market power in a restructured short-run electricity generation market. An algorithm that finds the maximum profit for a dominant firm in a regional electricity market, and thus determines its optimal dispatch strategy, is developed to analyze the effect of transmission. This algorithm iteratively solves a linear programming model to approximate the non-linear profit maximization problem for a

dominant firm. The algorithm demonstrates the ability of a dominant firm to exercise market power by strategically using its generation resources in different regions to take advantage of congestion on the transmission grid. The model includes the movement of electricity between multiple regions subject to the thermal capacity limits on the transmission lines. The dominant firm can act strategically to congest transmission lines and affect the market boundaries. Once transmission is congested and the market has been defined, a dominant firm may have increased market power because of a smaller competitive fringe (Borenstein, Bushnell, and Stoft 1998; Cardell, Hitt, and Hogan 1997; Hogan 1997; Stoft 1997; Stoft 1999b).

### 1.3 Specific Problem

The model developed in this research is applied to study the potential for market power in the Colorado electricity generation industry. Previous research has already determined that market power may be a significant problem if Colorado decides to restructure (Colorado Office of Consumer Counsel 1999; Sweetser 1998a). However, by not addressing the ability of transmission to allow competition from the surrounding regions, these market power estimates may be misleading. This research provides better estimates of potential market power in a restructured Colorado electricity industry by allowing competition with the surrounding regions through transmission. The model is used to evaluate potential market power mitigation strategies, such as enhancing the

transmission grid, divesting the dominant firm's generation assets, promoting entry into the generation market, and limiting the dominant firm's ability to withhold capacity.

#### 1.4 Objectives

To address the general problem of market power and the specific problem of market power in Colorado, this research

- Develops an algorithm to perform market power analysis on electricity regions with a dominant generating firm;
- Develops a model of the perfectly competitive dispatch of electricity to be used as a baseline in the analysis of market power and as a sub-problem in the profit maximization algorithm;
- Determines the strategic actions that a dominant firm with generation resources in multiple regions can take to maximize its profits;
- Applies the market power algorithm to determine the potential for market power in Colorado's electricity industry;
- Investigates the correlation between the capacity of transmission lines transporting electricity into a region and regional generation prices;
- Investigates the correlation between the use of transmission lines transporting electricity into a region and regional generation prices;
- Determines the extent to which investment in the transmission grid is an effective market power mitigation strategy for Colorado; and
- Determines the extent to which other market power mitigation strategies, such as divesting the dominant firm's generation resources, promoting entry into the generation market, and limiting the ability of the dominant firm to withhold capacity, are effective as potential policies for Colorado.

Chapter 2 provides background on the electricity industry while Chapter 3 reviews relevant literature of market power analyses in the electricity industry. Chapter 4 develops the perfect competition and imperfect competition models and Chapter 5

addresses the application of the models to Colorado's electricity industry. Chapter 6 discusses the market power results for Colorado and the effect of transmission on market power, while the policy analysis of potential mitigation strategies to limit market power in Colorado is in Chapter 7. Chapter 8 summarizes the research and recommends areas for future research.

## Chapter 2

### THE ELECTRICITY INDUSTRY

This chapter provides background information on the electricity industry related to the economic dispatch of generation, models of competitive electricity markets, and transmission.

#### 2.1 Economic Dispatch of Generation

The federal government has encouraged interconnection and coordination among utilities since the 1930s when Part II of the Federal Power Act was enacted. The passage of the Act in 1935 empowered the Federal Power Commission "to divide the country into regional districts for the voluntary interconnection and coordination of facilities" (FERC 1981). This coordination of utilities can occur at several different levels. Economic dispatch refers to a single utility dispatching its generating units in a least-cost or merit order. When two or more utilities agree to economically dispatch their units, the term central dispatch is often used (Fox-Penner 1998, 35). For the purpose of this research, "economic dispatch" is used to represent both of these levels of dispatch.

Economic dispatch involves minimizing the cost of meeting demand with a set of coordinated generating units. Costs are minimized when every on-line generating unit has a marginal cost ( $MC$ ) less than the  $MC$  of any generating unit not on-line. Therefore,

economic dispatch refers to the proper loading on each generating unit such that the total demand is met at the lowest possible production cost. The dispatch must also be consistent with other factors and constraints, such as the capacities of the transmission lines, transmission losses, spinning reserve requirements and environmental considerations (FERC 1981).

The time frame of the dispatch of generation is another important issue. The traditional division is the short run and long run. Firms are limited to existing capital plants in the short run, but they can add or retire these "fixed assets" in the long run (Fox-Penner 1998, 25). In the electricity industry, the short run can be further reduced to the very short run, when the market moves real power from a set of generators to meet customer demand. The matching of supply and demand often occurs on an hourly spot market (Hogan 1998). This research refers to the hourly spot market for generation as the short run.

The following example illustrates an economic dispatch of generation for a given short-run demand, assumed to be perfectly inelastic. This example also shows that the economic dispatch and the perfectly competitive outcomes result in the same solution (Hogan 1998). Figure 3 displays a market with six plants and a demand of  $Q$ . Each plant has a constant  $MC$  and the horizontal summation of these  $MCs$  results in the short-run supply curve. In this example, Plants 1 through 5 all generate electricity to meet demand. The first four plants operate at full capacity and Plant 5, the marginal plant, only generates enough electricity to meet the remaining demand. This marginal plant

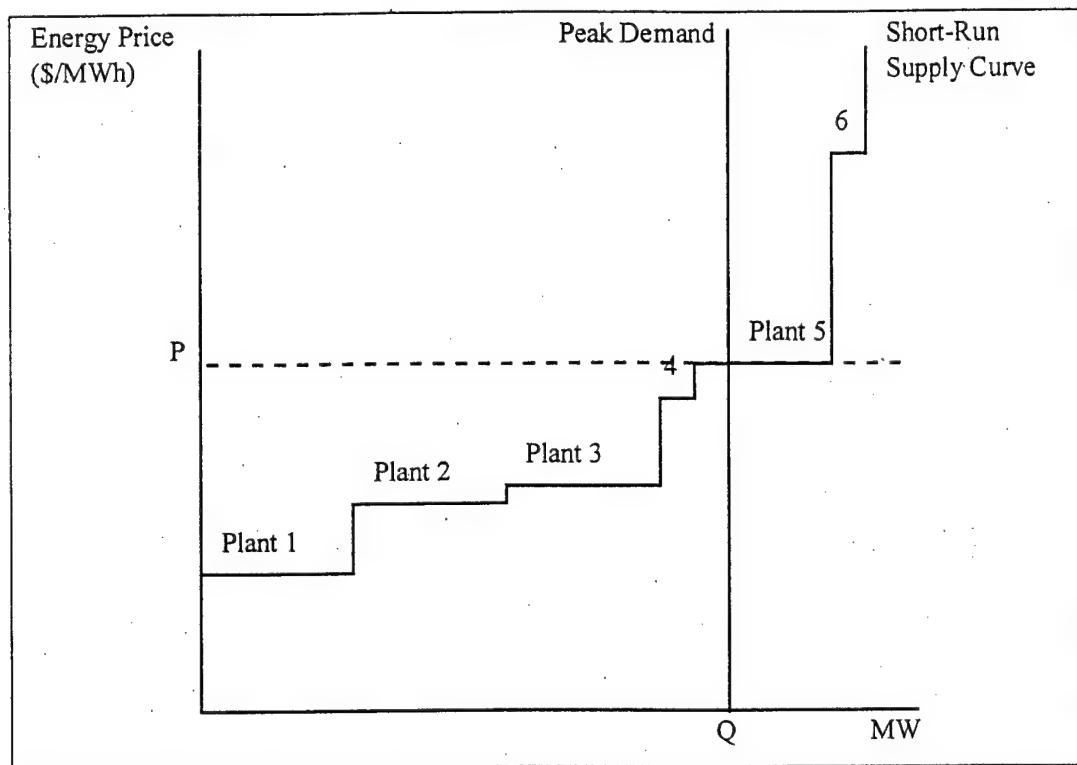


Figure 3: Short-Run Electricity Market

determines the market price,  $P$ . Since Plant 6 has a  $MC$  greater than  $P$ , it will not sell its generation at the given demand of  $Q$ . In a perfectly competitive market, only plants with  $MC \leq P$  will sell their generation, and thus an economic dispatch approximates a perfectly competitive market.

The benefits from coordination achieved through an economic dispatch of electricity generation go beyond using cheaper generation units first. The Federal Energy Regulatory Commission (FERC 1981) lists the following economic benefits from coordination:

- Economies of scale
- System reliability
- Operating reserve
- Installed reserve
- Staggered construction
- Economy energy interchange
- Load diversity
- Maintenance coordination
- Maximizing hydroelectric utilization
- Diversity of errors
- Siting flexibility
- Resource diversity
- Maximum transmission utilization
- Emergency response
- Utility planning and operating quality.

Future competitive generation markets need to maintain some level of coordination so these benefits can continue to be captured.

## 2.2 Competitive Electricity Markets

Competitive electricity markets can be categorized by the contractual agreements used for coordination. Bilateral trades lead to a bilateral contract market while multilateral trades result in a power pool.

### 2.2.1 Bilateral Contracts

The most common coordination arrangements in wholesale generation markets are bilateral contracts in which two utilities agree to exchange energy, or buyers and sellers individually contract with each other for power (FERC 1981). Contracts may guarantee capacity for many years with fixed price contracts, or the contracts can serve

an hour by hour spot market. Permission is not required by an outside authority to allow the trade, price is not regulated, and performance disputes between buyers and sellers are settled according to the terms of the contract or by resorting to the legal system (Fox-Penner 1998, 190).

Modeling a bilateral contract market is difficult because of the unlimited number and variety of contractual agreements. Because prices are not transparent, buyers and sellers have to shop to discover prices. A bilateral contract market emphasizes neither homogeneity nor a single market-clearing price because of the various types of contracts and asymmetric negotiating power among buyers and sellers (Fox-Penner 1998, 191).

### 2.2.2 Power Pools

There are also important multilateral associations and contracts in the electricity industry called power pools, or “poolcos” (Fox-Penner 1998, 36). Power pools establish arrangements for joint planning on a single system basis, provide for centralized dispatch of generating facilities, and form contractual requirements relating to generating capacity and operating reserves together with specific financial penalties if these are not met (FERC 1981).

The operation of a power pool is very similar to the economic dispatch of generation except that the marginal costs are not public information in a competitive environment. For each time period, firms bid quantities of generation at different prices, not necessarily their marginal costs. At the same time, the consumers submit their

demand bids. A dispatcher matches these bids to determine the marginal plant. The bid of the marginal plant becomes the price for generation in that given hour. Unlike bilateral contracts, the market-clearing price is transparent to all participants in a power pool (Fox-Penner 1998, 187).

Proponents of power pools believe that competition in the generation industry will force firms to bid the marginal costs of their generating units (Rudkevich, Duckworth, and Rosen 1998). Firms that bid higher than marginal cost risk not being dispatched while firms that bid less than marginal cost risk operating at a loss. If marginal costs are bid, the outcome approximates a perfectly competitive solution as was shown in Figure 3. However, firms may be able to bid strategically to increase price if the competitive pressure to bid marginal costs does not exist (Hogan 1998).

Region-wide power pools have been established in California, the Pennsylvania-New Jersey-Maryland (PJM) region, the New England region, and New York to facilitate wholesale competition in the generation market (Rudkevich, Duckworth, and Rosen 1998). One reason for the popularity of power pools is that they result in transparent market-clearing prices rather than a distribution of private prices found in bilateral contract markets (Fox-Penner 1998, 191). This research assumes a region-wide power pool for the perfect and imperfect competition models.

### 2.3 Transmission

The example of economic dispatch of electricity presented in Section 2.1 examines only an isolated market. The example would be more realistic, but also more complex, if it included a transmission network connecting many regions. The transmission network transports power and coordinates the efficient supply of electricity in both the short and long run. Joskow and Schmalensee (1983, 63) argue that the transmission network is the heart of a modern electric power system. However, accounting data imply that the transmission segment of the electric power system is the least significant of the three production stages. In an analysis of 1996 electricity prices, only 7% of the total price was attributed to transmission (EIA 1996a). Therefore, research on the electricity industry often does not focus on transmission issues, treating the transmission segment of the industry as a residual, lumping it with generation or ignoring it completely (Joskow and Schmalensee 1983, 62). However, the share of the total price that transmission represents does not indicate the importance of transmission in defining market boundaries.

#### 2.3.1 Movement Toward Open Access Transmission

Open access to transmission is critical to the full development of a competitive wholesale generation market and the lower consumer prices potentially achievable through competition (FERC 1996). When energy was first traded, the trades only involved bilateral transactions between two physically interconnected utilities that

utilized their own transmission capacity. Some utilities allowed others to access their transmission lines to support wholesale transactions, but they were not obligated to do so until the passage of the Energy Policy Act of 1992 (EPAct) (Bailey 1998). EPAct laid the foundation for open access of the transmission lines by giving the FERC new authority to mandate transmission access. However, this authority was only on a case-by-case basis and upon request. The FERC created open access to the transmission grid when it issued Order 888 (effective January 1, 1997). Under Order 888, each utility is required to provide transmission service to all requesters under terms and conditions comparable to those the utility provides itself for transmission of its own generation to its customers. This does not force utilities to place their generation and transmission assets in different companies, but it does require utilities to operate them as if they were independent (Fox-Penner 1998, 168-170). Each of these steps toward open access seeks to break up the vertical integration of the traditional industry in an attempt to prevent vertical market power and to facilitate competition.

Since implementation of Order 888, the FERC has investigated the use of Regional Transmission Organizations (RTOs), or Independent System Operators (ISOs), to further its goal of more independent transmission systems (Rose 1999). An ISO is a nonprofit independent system operator that would perform scheduling, dispatching, auctions, and other grid operations. In 1999 there were five FERC-approved RTOs, all of which were in the form of ISOs: the California ISO, the PJM ISO, ISO New England, the New York ISO and the Midwest ISO. There was also an ISO for the Electric

Reliability Council of Texas (ERCOT) which was not subject to FERC jurisdiction (Skinner 1999). The objective of the FERC was for all transmission owning entities in the United States to place their transmission under the control of an independent organization. It was believed that an independent organization could

- Improve efficiencies in transmission grid management,
- Improve grid reliability,
- Remove the remaining opportunities for discriminatory transmission practices,
- Improve market performance, and
- Facilitate lighter handed regulation.

The ultimate goal was to lower electricity rates for consumers (FERC 1999).

Independent transmission companies, or "transcos," have emerged as another option for control over transmission products and pricing. A transco would operate, maintain, plan, design, construct and sell transmission service for an integrated network for profit while being regulated by the FERC. Although ISOs have been preferred in the United States, the National Grid Co. of Great Britain is a good example of a successful transco (Hebert, Jr. and Rokach 1999). Advocates of transcos argue that the motivation for profits makes this approach more efficient than an ISO. The counter argument is that these same motives could make the transco an uncontrollable monopolist (Cicchetti and Long 1999; Michaels 1999). This research does not enter the debate of ISOs versus transcos. Instead, it assumes that complete open access across the transmission grid has been achieved and that no firm has the ability to exert vertical market power.

### 2.3.2 Transmission Pricing and Investment

Transmission continues to be regulated in restructured electricity markets because it still has the characteristics of a natural monopoly. The same pricing problems that have faced the industry over time do not necessarily go away with the introduction of ISOs and transcos. One of the primary problems is that investors must receive the proper price signals to expand the transmission system efficiently. The creation of ISOs and transcos does not necessarily eliminate the problems; it just transfers them to a new entity.

Regional differences in electricity prices result from the inability of the transmission lines to allow generation to flow from low cost to high cost regions. During some periods of demand, transmission lines can become congested, forcing generators in low cost regions to be “constrained off.” This results in the use of higher cost plants in other regions. These higher cost plants are “constrained on” because of the transmission congestion. Different marginal plants and prices can result across regions because of congestion. The difference between the regional prices is the congestion rent for the transmission line connecting the regions (Hogan 1998). The amount of time congestion occurs and the magnitude of the rents can be used to estimate the need for expansion of the grid. Repeated congestion between two regions is a natural signal to invest in more transmission (Fox-Penner 1998, 226).

An alternative to traditional regulation of transmission is the use of tradable transmission rights to capture congestion rents. Hogan (1998) introduced Transmission Congestion Contracts (TCCs) as a financial transmission right to be traded in a

competitive manner. There has been significant debate as to whether TCCs will enable transmission rights holders to capture the congestion rents. Oren (1997) argues that TCCs provide incentives to generators to behave strategically to capture the rents, resulting in the TCCs having no value for their holders. This viewpoint is also supported by experimental results from Bakeman, Rassenti and Smith (1997). However, Stoft (1999a) argues that the introduction of TCCs or some other form of transmission right will serve as a curb on market power. Experimental results from Weiss (1998a) endorse Stoft's argument. Therefore, the effectiveness of TCCs at pricing transmission is not universally accepted.

Technological externalities associated with the electric network act as barriers to creating efficient markets for transmission services. Chao and Peck (1996) design a market mechanism using tradable transmission capacity rights that incorporates the externalities associated with transmission congestion and transmission losses. Their framework provides a consistent conceptual basis for pricing transmission services under alternative structures of the electricity market.

Without entering the debate of who captures the congestion rents or attempting to determine efficient pricing of transmission, it can still be shown that transmission capacity will play a significant role in determining generation prices as the industry restructures. In their study of market power in California and New Jersey, Borenstein, Bushnell, and Knittel (1999) find that limits in transmission capacity can have important impacts on the level of competition by restricting the potential short-term entry into the

market. They find that increasing transmission capacity into a region can have strikingly large impacts on the competition in that region. This research analyzes the effect that investments in transmission can have on horizontal market power in generation, but does not address pricing of transmission or the decision process for investments in new transmission. Additional market power issues associated with transmission are discussed in the literature review.

## Chapter 3

### LITERATURE REVIEW

Unlike the issues specific to the electricity industry discussed in the previous chapter, market power is not unique to this industry. This chapter discusses how the theory of market power applies to the electricity industry and reviews previous research on market power in the industry. After the introduction to market power, the chapter is organized according to how the previous research has dealt with the transmission of electricity. The discussion of previous research is used to frame the model and analysis in the following chapters.

#### 3.1 Market Power

Firms can exercise horizontal and vertical market power in the electricity industry. An example of vertical market power is a firm that owns transmission or distribution in addition to its generation assets and favors itself in the delivery of electricity (Rose 1999). The FERC has taken steps to achieve open access of the transmission system in an attempt to eliminate vertical market power in the electricity industry. In contrast to vertical market power, horizontal market power takes place within a single stage of production, such as generation (Rose 1999). A single generation firm often has a high concentration of generators in a given service area because of the

evolution of the electricity industry in which regulated firms were granted exclusive franchises. The transmission grid, however, has the capability to expand markets geographically and introduce competition across service areas (Werden 1996). Therefore, the capacity of the transmission grid can affect the amount of horizontal market power within a region.

The relevant question in the electricity industry is the degree of market power, not whether there is market power (Joskow 1995). One measure of the degree of market power is the Lerner Index. The Lerner Index can be defined as  $\left( \frac{P - MC}{P} \right)$ , where  $P$  represents the market price and  $MC$  is the marginal cost of the marginal producer. The price in a perfectly competitive market is often used instead of  $MC$  since the marginal plant may differ in markets with and without market power. The Lerner Index can be used as a retrospective indicator of market power by quantifying the percentage deviation of the price of a product from the theoretical price in a perfectly competitive market (Borenstein, Bushnell, and Knittel 1999). A modification of the Lerner Index is the Price-Cost Margin Index (PCMI), which is defined as  $\left( \frac{P - MC}{MC} \right)$ . The difference is that the PCMI uses the competitive price, or  $MC$ , in the denominator. This facilitates comparison across various scenarios that may have different prices (Rudkevich, Duckworth, and Rosen 1998). The link between the Lerner index and the PCMI is:

$$\text{Lerner Index} = \left( \frac{\text{PCMI}}{1 + \text{PCMI}} \right) \quad (3.1)$$

The Department of Justice (DOJ) merger guidelines state that a market is considered competitive if prices do not exceed their perfectly competitive level by more than 5% (U.S. Department of Justice and Federal Trade Commission 1992). A drawback to the Lerner Index and PCMI is that they cannot easily be measured because costs are usually private information only known by the producers (Borenstein, Bushnell, and Knittel 1999).

Concentration measures are also used as a proxy to measure market power. Government agencies concerned with market power have often relied on projected changes in concentration measures to analyze the impact of structural change in the market. A commonly used concentration measure is the Herfindahl-Hirshmann Index (HHI). The HHI is the sum of the squares of the market shares of each firm in the market. The two extremes are an HHI value of 10,000 for a monopoly ( $100^2$ ) and 0 if there are an infinite number of equal size firms. A market with ten firms with identical market shares has an HHI of 1,000. The DOJ and Federal Trade Commission (FTC) use HHI guidelines in addition to the price-cost margin for evaluating mergers. They consider an industry with an HHI between 1,000 and 1,800 as "moderately concentrated." Industries with HHI levels above 1,800 are referred to as "highly concentrated," indicating that a merger could create market power.

The problem with the use of concentration measures as a measure of market power is that there are many factors beyond the number and size of firms in a market that impact the degree of competition within an industry. Concentration measures rely on regulation-era market share data, but fail to account for the incentives of the producers, elasticity of demand, or the ability of the transmission grid to limit potential competitors in a market (Borenstein, Bushnell, and Knittel 1999). Several studies show that the use of the HHI to determine market power in the electricity industry is inadequate (Borenstein, Bushnell, and Knittel 1999; Cardell, Hitt, and Hogan 1997; Rosen and Kroll 1996; Rudkevich, Duckworth, and Rosen 1998).

The Borenstein, Bushnell, and Knittel (1999) paper demonstrates that the Lerner Index is a better measure of market power than the HHI in the electricity industry using the California market as an example. The output of the two largest generation firms makes up a large percentage of all electricity generated at lower levels of demand since the firms cannot increase price by reducing their production. Since the HHI is determined using historical data, i.e., which plants were dispatched, the HHI reflects this high concentration and indicates market power should be a concern at the low levels of demand. As demand increases, the two firms are able to increase price by reducing their production. At the higher price, the competitive fringe increases its production causing the HHI to decrease. Therefore, the HHI decreases for the periods of demand when market power is being exercised. In contrast, the Lerner Index correctly shows that markups increase as demand increases since it compares prices in the perfect and

imperfect competition cases. This example demonstrates why the HHI and other concentration measures can be misleading when they are used to measure market power in the electricity industry. Therefore, this research uses price comparisons rather than concentration measures to evaluate market power.

### 3.2 Market Power Models in the Electricity Industry

A variety of different models have been used to estimate the potential for market power in electricity generation. The remainder of this chapter reviews these different market power models and the variety of issues that they have addressed. The models are categorized by how they deal with transmission. Models that do not address transmission at all are presented first. The models that address transmission are further divided into the models that analyze the strategic use of the transmission lines and those that do not.

#### 3.2.1 Models Without Transmission Constraints

Many models deal with transmission exogenously or do not include transmission and thus do not address the effect transmission can have on market price. Green and Newbery (1992) developed one of the most cited market power models, but they ignore the effect of transmission. They modeled the British electricity market after the generation of the public utility had been privatized and divided into three firms. The coal, oil, and gas-powered stations were divided between two dominant firms that competed against each other and against other generators. The nuclear power stations

were transferred to a third firm that remained in the public sector. The study implements a supply function equilibrium, a technique developed by Klemperer and Meyer (1989) that characterizes the equilibrium in supply schedules for each competing firm. By assuming smooth supply functions for each firm, a linear demand function, and symmetric firms, the first order conditions of the profit maximization objective function are computed to determine the supply schedules for each firm. The transmission of generation from the interconnection with France and Scotland is assumed to be constant throughout the year. Although the paper discusses asymmetric firms, it only applies the model to symmetric firms. The Nash equilibrium results in a high markup over marginal cost and substantial deadweight losses across a range of different slopes of the demand curve. By allowing entry into the market, prices are somewhat lower, but only at the cost of excessive entry. Green and Newbery also modeled a scenario where the two dominant generating firms were divided into five symmetric firms, and this resulted in even lower prices than the scenario with entry. They conclude that the British government underestimated market power by hoping Bertrand competition would result in competitive prices in a concentrated market.

In another market power analysis of the British electricity spot market, Wolfram (1995) measures price-cost markups to estimate market power. She shows that the two dominant suppliers are charging prices above marginal cost, but not nearly as high as models such as Green and Newbery's have predicted. She attributes the lower prices to

strategic pricing by the two dominant firms to deter entry into the market and to the threat of substantial punitive regulatory action.

Andersson and Bergman (1995) extend the research of Green and Newbery with a study of the Swedish electricity market. They also use the supply function equilibrium, but they allow for asymmetric firms. They conclude that given the current market structure and high degree of concentration on the supply side of the Swedish electricity market, deregulation is not a sufficient condition for lower equilibrium prices.

Since the work on the British and Swedish electricity markets, additional research points out some flaws in the approach used by these authors. Wolak and Patrick (1996) use data from the Scottish and the English spot markets for electricity to analyze market behavior and find that setting high prices is not the only means for exercising market power. They find that the firms can game the operation of the market to maximize the capacity payments they receive from the operator of the spot market. Therefore, there are means of exercising market power outside the traditional channel of price setting. Weiss (1998b) uses an experimental approach to analyze market power and argues that increasing the number of sellers competing in a market may not be sufficient to lower prices. When transmission capacity is limited and lines become congested, firms may experience local market power even with the addition of new firms. Weiss's research is just one example of research that shows the importance of including transmission in market power analyses. This research focuses on the influence of transmission on market

power, so the remainder of this chapter reviews research that addresses the transmission issues.

### 3.2.2 Models with Transmission Constraints

Although there are many models that include transmission in their analysis of market power, the range of completeness in the treatment of transmission varies greatly. Two large distinctions are made between models: (1) do they analyze the strategic manipulation of transmission by the generation firms? and (2) do they include the engineering complexity of the transmission grid? This section divides models by whether they analyze the strategic use of transmission, but it also differentiates between the models that include the engineering complexity of electricity transmission.

#### 3.2.2.1 No Analysis of the Strategic Use of Transmission

Many research efforts identify when there is congestion in the system, but do not analyze how firms behave strategically to congest the transmission lines. Congestion isolates markets based on the market demand and generation and transmission properties in a region. As these models show, isolation of markets can increase market power.

In an attempt to determine the effective level of concentration, or a concentration level promoting competition, in the wholesale electricity markets in the contiguous United States prior to restructuring, Schmalensee and Golub (1984) find that effective concentration is highly dependent on the adequacy of transmission capacity in each area.

They were unable to acquire usable nationwide transmission capacity data, so their focus was on determining single-market equilibria for 170 market areas rather than on multi-market equilibria. The authors simulate an oligopolistic equilibrium for each area varying transmission capacity into the area, marginal cost, and demand elasticity. They determine that estimates of effective concentration are much more sensitive to variations in transmission capacity than to changes in transmission costs because transmission capacity allows for entry into the market. They conclude that deregulation should proceed with extreme caution and that prior to deregulation a more detailed analysis of each region should be performed, taking into account the characteristics of existing transmission facilities.

The discussion now focuses on empirical models that look at market power in specific regions. Hobbs (1986) uses linear programming models to obtain short-run spatial price equilibria for a deregulated bulk power market in upstate New York. His baseline case is a price regulation model that minimizes costs. He also models a Nash-Bertrand equilibrium in which each firm believes that rivals will not react to price changes and a limit pricing equilibrium that is designed to discourage new firms from entering the market. With these models, Hobbs captures the spatial variations in production costs and demand functions that most previous models of imperfect competition could not address. He states that the advantages of formulating the models as linear programs are that they can solve very large problems and that lower and upper bounds to prices can be approximated. The Nash-Bertrand equilibrium model results in a

more intense level of competition than does limit pricing. Hobbs concludes, however, that the New York consumers will, on average, be worse off under deregulation because they would consume less and pay more.

California is one of the states that has already deregulated its electricity industry. An electricity spot market, the Power Exchange or PX, began accepting bids for day-ahead supplies of electricity on March 31, 1998. The exact rules of the operation and competitive structure of the market have continued to evolve since its inception. Market power remains a concern, inducing several studies on this issue. Borenstein and Bushnell (1999) developed a Cournot simulation model to gain insight into the competitive outlook of the California market. Their Cournot simulation model improves upon other simulation models by including a profit-maximizing algorithm for each firm. The Cournot equilibrium is estimated such that each firm is producing its profit-maximizing quantity given the quantities produced by the other Cournot participants in the market. This model meets an hourly demand represented by a constant elasticity demand (CED) function. Analysis is performed with the CED using elasticities of 0.1, 0.4, and 1.0. The simulation allows excess capacities from regions outside of California to compete in California as part of the competitive fringe. The ability of imported generation to compete is limited by the thermal limits on the transmission lines into California. The authors focus on the static problem of electricity dispatch because of the notoriously difficult nature of addressing dynamic competition in the electricity market. They state that models attempting to address dynamic competition often yield indeterminate results.

Based on their model of the static dispatch of electricity, Borenstein and Bushnell conclude that large generation firms in the restructured California electricity market could potentially find it profitable to restrict output to raise price. They analyze potential mitigation policies to reduce market power in California and determine that divestiture of the large firms' generation units and expansion of the transmission paths between California and neighboring areas could each limit market power. Borenstein and Bushnell suggest that the greatest reduction in market power, however, could come from policies that increase the elasticity of demand for electricity.

Borenstein and Bushnell apply the above model of California to address a number of market power issues. A paper by Borenstein, Bushnell, and Knittel (1999) focuses on comparing measures of market power, once again using California as an example. As discussed in Section 3.1, this paper demonstrates the weakness of the concentration measures based on historical data and proposes the use of market simulation models based on plant level data. Bushnell (1998) uses the same model again, but concentrates on the potential strategic use of hydroelectric generators. He demonstrates that the ability of firms owning hydro resources to shift their supply between peak and non-peak periods of demand can greatly reduce, or further increase, the frequency and severity of market power. Another paper analyzes whether restructuring has caused California's wholesale electricity market to deviate from the competitive ideal prices, and if so, by how much (Borenstein, Bushnell, and Wolak 1999). Using actual data from the summer of 1998, the authors conclude that market power was a significant factor on prices during that

time. A common theme across all of this research is that deregulation is not necessarily a mistake just because market power may exist. Instead, these and other research efforts attempt to assess the costs and benefits of the restructuring of the electricity industry.

The useful insights that quantitative models can bring to electricity restructuring are exemplified in a study of California conducted by Kahn, Bailey, and Pando (1997). They develop a multi-area chronological production simulation model of electricity restructuring in California. The most interesting of their findings is that transmission congestion will increase because of the increased regional trade. They divide the Western System Coordinating Council (WSCC) into multiple transmission areas and find that California will become more dependent on imports to meet its electricity demand. Even with the increased reliance on imports, the authors find that the congestion costs will be small because of similar marginal costs of generation in California and the surrounding regions. They also argue that local generators will gain economic rents from marginal cost pricing. Although some plants such as the hydroelectric plants may receive large rents, they feel that the rents summed across all generators are not particularly large given the high fixed operating and maintenance costs of some plants. Other issues this study analyzes are the potential for new entry into the market and the siting trade-off between transporting gas into the region for local generation and transmitting power from remote generation. By not addressing strategic behavior by the generating firms, their estimations of the transmission congestion and rents accrued by local generators under restructuring are lower than what would be expected in practice in the restructured

California electricity industry. By including the transmission across the WSCC, however, they provide a framework to address market power and transmission in more detail.

The state of Colorado faces the decision whether it should follow the lead of California and other states and restructure its electricity industry or maintain the current regulation of the industry. One of the largest concerns for Colorado is market power and its effect on electricity prices. Sweetser (1998b) argues that the dominant firm in the state, Public Service Company of Colorado (PSCo), will have the ability to set prices above marginal costs up to 93% of the year during the years 2002-2005 if generation is deregulated. First, Sweetser simulates the perfectly competitive dispatch of electricity in eastern Colorado, western Colorado, and Wyoming separately. Using a derivation of the Lerner Index, he then determines when and to what degree PSCo could apply a markup over its marginal cost based on the uncommitted fringe generation available to compete in eastern Colorado across the transmission lines at different levels of demand. Using this model, Sweetser investigates the effect of increased transmission within the region, entry of new generation into the market, and divestiture of PSCo's assets on market power. He concludes that increasing transmission has almost no effect on the price markups, but he acknowledges that this may not be the case if additional regions were considered in the analysis. The other mitigation strategies, however, result in decreased market power for PSCo. In addition to being limited to generation assets in Colorado and Wyoming, Sweetser's approach relies on an ex ante analysis of the perfectly competitive

simulations rather than modeling the strategic dispatch of PSCo's generation resources. In an imperfectly competitive environment, however, a firm can alter its production pattern in way that violates the assumption of market-wide economic dispatch (Borenstein, Bushnell, and Knittel 1999).

Sweetser's research led to additional market power research in Colorado. The Electricity Advisory Panel, appointed by the State of Colorado to determine the impact of restructuring Colorado's electricity industry, contracted Stone and Webster Management Consultants (1999) to predict the price of electricity in Colorado through the year 2017 using a dynamic simulation model. Stone and Webster developed a transmission grid of the whole WSCC and assume it does not change over time even though they allow demand to grow and model entry of new generation into the market. In its analysis, Stone and Webster only analyze market power and allow for strategic bidding by PSCo in one of its scenarios. However, the bidding strategies used in this scenario vary only by month, rather than by hour to correspond with the hourly fluctuations in the demand for electricity. This approach does not relate the magnitude of the markup to the hourly level of demand. For example, in the simulation PSCo applies the same markup on its bids for the hours with the lowest and highest demand within the same month. Despite this representation of strategic bidding, the results show that PSCo will have market power at least through the year 2007, and maybe even longer.

The main focus of the Stone and Webster study was the comparison of price given continued regulation to price in a perfectly competitive electricity industry. Given their

assumed market rules for the competitive case, they conclude that price will be much greater in a competitive industry than with continued regulation. Even though it has been argued that the higher prices in the competitive scenario are directly related to the assumptions in the study, the Stone and Webster conclusions have been influential in determining the direction of Colorado's restructuring policy. Because the focus of the Stone and Webster study was not market power and its analysis of market power is not very thorough, the study provides no additional insights on the potential mitigation of market power or the effect of increased transmission capacity.

Due to the shortcomings of the previous analyses of market power in Colorado, Colorado's Office of Consumer Counsel (OCC) hired the Tellus Institute to conduct another market power analysis (Colorado Office of Consumer Counsel 1999). The Tellus study identifies problems with the market power analysis performed by Stone and Webster and uses a model developed by Rudkevich, Buckworth, and Rosen (1998) to analyze Colorado's potential market power. Using a derivation of the Klemperer and Meyer (1989) supply function equilibrium, this study also indicates that PSCo will have considerable market power under restructuring. Similar to Sweetser's work, this study does not consider generation outside Colorado and Wyoming in a realistic manner. It aggregates transmission from western Colorado and Wyoming into a single transmission line into eastern Colorado. The study suggests actions for Colorado to consider in order to mitigate market power, but it does not analyze the effectiveness of any of these alternatives. Even though the OCC study does not include a realistic representation of

Colorado's generation imports and exports, it provides the most accurate analysis thus far of market power in Colorado. All the studies of Colorado point to potential market power problems, but this research improves upon the market power estimates of the previous research by including the interaction with the surrounding regions and incorporating the strategic use of transmission by the dominant firm. These improvements allow for more meaningful policy analysis on how to mitigate market power.

The models discussed so far have abstracted from the details of transmission by using a variant of a standard transportation model to describe the transmission grid and by only focusing on real power. More realistic representations of electric power networks incorporate loop flow and reactive power in addition to real power. Loop flow is the phenomenon that power travels instantaneously along all parallel paths. It creates widespread externalities in the markets for electric power and its complexity only grows with the size of the system (Chao and Peck 1996). Reactive power is a purely mathematical concept used to define how far the current is out of phase with the voltage. Including reactive power in the model allows the system to become congested due to voltage constraints in addition to thermal, or capacity, constraints (Hogan 1993). Few models have been developed that capture the engineering complexities of transmitting electricity (Cardell, Hitt, and Hogan 1997; Chao and Peck 1996; Hogan, Read, and Ring 1996) and these research efforts have not been applied to specific regions to answer policy questions regarding market power and restructuring. However, these models do

provide a better framework for capturing the reality of the movement of electricity. This research makes simplifying assumptions about the transmission grid consistent with the other models presented in this section. These assumptions are made so that the model can be applied to real data to investigate the relationship between market power and transmission.

### 3.2.2.2 Strategic Use of Transmission

A missing element from the research in the previous section is an analysis of the strategic behavior by firms to congest the transmission lines. Many of the models incorporate explicit transmission grids, thermal limitations on the transmission lines, and some even look at the impact on market power of increasing transmission flow into the region being studied. None of these studies, however, analyze whether the transmission grid will be viewed differently by firms in regulated and unregulated markets. Stoft (1997) argues that it will be socially beneficial to build a grid that is “more robust” in an unregulated market than what is optimal in a regulated environment. In fact, the Kahn, Bailey, and Pando (1997) research discussed in Section 3.2.2.1 supports this claim. They showed that even in the absence of market power, the increased regional trade in a competitive market increases transmission congestion. Stoft shows how the transmission grid defines the boundaries in unregulated markets and how a congested line can cut a market into two non-competing regions. Generating firms may have an incentive to reduce output in order to congest a line and increase their market power. Therefore,

unused capacity on the transmission grid may be required in unregulated markets to discipline firms to price their generation closer to marginal costs. Stoft uses game theory examples to demonstrate the potential strategic behavior by firms.

A paper by Borenstein, Bushnell, and Stoft (1998) discusses in more detail much of the theory in the work by Stoft (1997; 1999b). The Borenstein, Bushnell, and Stoft paper also shows that there may be no relationship between the effect of a transmission line in spurring competition and the actual electricity that flows on the line in equilibrium. The authors develop a model of two identical, geographically distinct markets that are linked through a single transmission path, and show the crucial role transmission capacity has in determining the market outcomes. They derive the "threshold" transmission capacity that is sufficient for completely integrating the two markets. They show that no pure-strategy Cournot equilibrium outcome can exist for capacities less than this threshold, but rather mixed-strategy equilibria evolve. The authors use the model developed by Borenstein and Bushnell (1999) to demonstrate the potential impact of transmission capacity on the major north-south transmission path in California. The Borenstein and Bushnell model does not determine optimal strategies firms can use to take advantage of the transmission path, but it can be used to assess the impact of alternative strategies.

A model that captures potential action by competing firms is described in two papers, Hogan (1997) and Cardell, Hitt, and Hogan (1997). This model shows that there may be situations in congested networks where a firm can exercise market power by

increasing its production in surrounding regions in addition to restricting its production in the local region in order to congest transmission lines into the local region. This strategy may lower the prices it receives on generation in the surrounding regions, but could constrain the network to allow it to charge higher prices in the local region. As long as the benefits in the local region are greater than the losses in the surrounding regions, this is a profitable strategy. Both of these papers also show the interaction effects on the grid captured by including loop flow and reactive power in market power models. However, the resulting model is highly non-linear and can be difficult to solve. A relaxed form of the problem is introduced, but it still has the same non-linearity problems. The authors contend that the model can be used to look at large, more realistic problems, but the model has not been applied to a regional electricity market. The engineering complexity in this model increases the interaction between the transmission lines and may increase the profitability of a dominant firm's strategic behavior due to increased congestion on the transmission grid. Therefore, omitting this engineering complexity may bias the market power results downward, but the omission allows for increased tractability. This research models the strategic actions discussed in the Hogan (1997) and Cardell, Hitt, and Hogan (1997) papers without the added complexity of loop flow and reactive power. The effect of transmission on market power in a regional electricity market and the potential policy implications can be approximated using a model without the engineering complexity.

## Chapter 4

### MODEL FORMULATION

This chapter formulates an algorithm to maximize a dominant firm's profits in a competitive wholesale electricity generation market. By maximizing profits across multiple regions, the algorithm captures strategies a dominant firm can adopt to take advantage of transmission constraints. The model is used to analyze the effect transmission has on the ability of the dominant firm to exercise market power. First, the economic dispatch of generation is modeled. This model approximates the perfect competition solution and is used as the baseline in the analysis of market power. An algorithm that uses the perfect competition model as a sub-problem is then formulated to approximate the non-linear programming profit maximization problem of a dominant firm.

#### 4.1 Perfect Competition Model

Before analyzing market power in electricity generation markets with a dominant firm, a linear programming model is formulated to approximate the perfectly competitive solution, or the economic dispatch of electricity. A perfectly competitive solution assumes that each firm, and thus each generating unit, is a price taker. The linear programming model minimizes the cost of meeting a fixed demand subject to several

constraints. These constraints ensure that reserve requirements and demand are met, limit production and reserves by each plant to its capacity, and limit transmission to the capacity of the lines. This model results in an economic dispatch of generation to meet the hourly, or short-run, demand across regions.

The perfect competition model assumes a joint economic dispatch of all generating units. It ignores horizontal market power issues with generation and does not address regulatory requirements other than imposing a spinning reserve requirement on each firm. It assumes that all units must participate in the power pool. In addition, the model accounts for capacity constraints on transmission lines, assuming open access to the transmission grid. It does not address potential vertical market power issues involving transmission and does not model the physical laws determining power flow.

As discussed in Section 2.1, an economic dispatch approximates the competitive dispatch of generation. This framework is used to develop a model that minimizes the cost of meeting short-run demand for an electricity generation industry with multiple regions. Assume that a single transmission line connects two regions, regions 1 and 2. The change in price in region 1 based on the availability of transmission from region 2 demonstrates how the economic dispatch example from Section 2.1 changes when multiple regions and transmission constraints are considered. To simplify the graphical analysis, the supply curve in Figure 4 is assumed to be linear rather than stepped as it was in Section 2.1. Figure 4a shows that the price in region 1 ( $P_1$ ) is determined by the intersection of the demand ( $D_1$ ) and supply ( $S_1$ ) curves in region 1 when there is no

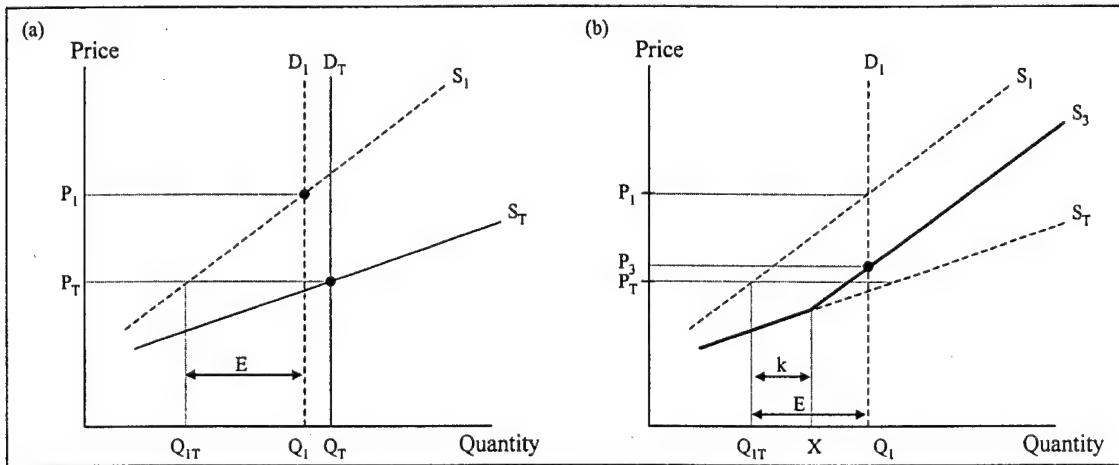


Figure 4. Transmission Effect in Two-Region Perfect Competition Example

transmission between the two regions. Figure 4a also demonstrates the resulting equilibrium from unlimited transmission capacity between regions. The added demand and supply from region 2 shift the demand ( $D_T = D_1 + D_2$ ) and supply ( $S_T = S_1 + S_2$ ) curves to the right. The new equilibrium is at price  $P_T$  and quantity  $Q_T$ . A price of  $P_T$  reduces the quantity produced in region 1 from  $Q_1$  to  $Q_{IT}$ . This requires a total of  $E$  megawatts of electricity to be exported out of region 2 to meet the demand in region 1. The direction of the change in price depends on the magnitude of the shifts of the supply and demand curves. Price could increase if the demand curve shift is more significant than the supply curve shift.

The determination of price for region 1 becomes more complicated when the transmission line is congested. Figure 4b shows a resulting equilibrium and price with a transmission capacity of  $k$  megawatts ( $k < E$ ) between the two regions. At the price  $P_T$ , a total of  $E$  megawatts from region 2 are still needed in region 1, but the line becomes

congested and only  $k$  megawatts are transferred. At that point the new supply curve in region 1 ( $S_3$ ) shifts and resumes the same slope as  $S_1$ . When the line is congested, only the higher cost supply in region 1 can be used for the remaining demand in region 1. The resulting price ( $P_3$ ) will be between  $P_1$  and  $P_T$ .  $P_3$  approaches  $P_T$  as  $k$  increases, and approaches  $P_1$  as  $k$  decreases. If  $k$  is greater than  $E$ , the line is uncongested. This analysis becomes more complicated when multiple regions and a more detailed transmission grid are considered. The linear programming model formulated in this section solves for the economic dispatch across multiple regions while considering transmission capacity between regions.

The network flow representation of the linear program is shown in Figure 5. The generating units in the first region are represented by nodes  $P_{11}, \dots, P_{1m}$ . Similarly,  $P_{21}, \dots, P_{2n}$  and  $P_{r1}, \dots, P_{rz}$  represent the generating units in the second and  $r^{\text{th}}$  regions. Each of these nodes, or units, has capacity going into it with the amount generated and the amount set aside for reserves flowing out of the node. The arcs with reserves go to nodes representing each firm, not shown, to account for each firm's spinning reserve requirement. The arcs representing the flow of electricity from each plant go directly to the respective regional node,  $R_1$ ,  $R_2$ , or  $R_r$ . Also flowing into each regional node are the imports from other regions. The demand for each region and exports to other regions flow out of each regional node. The general rule of a network flow model is that the flow into each node must be equal to the flow out of the node. Figure 5 is referenced often to help explain the mathematical formulation of the model.

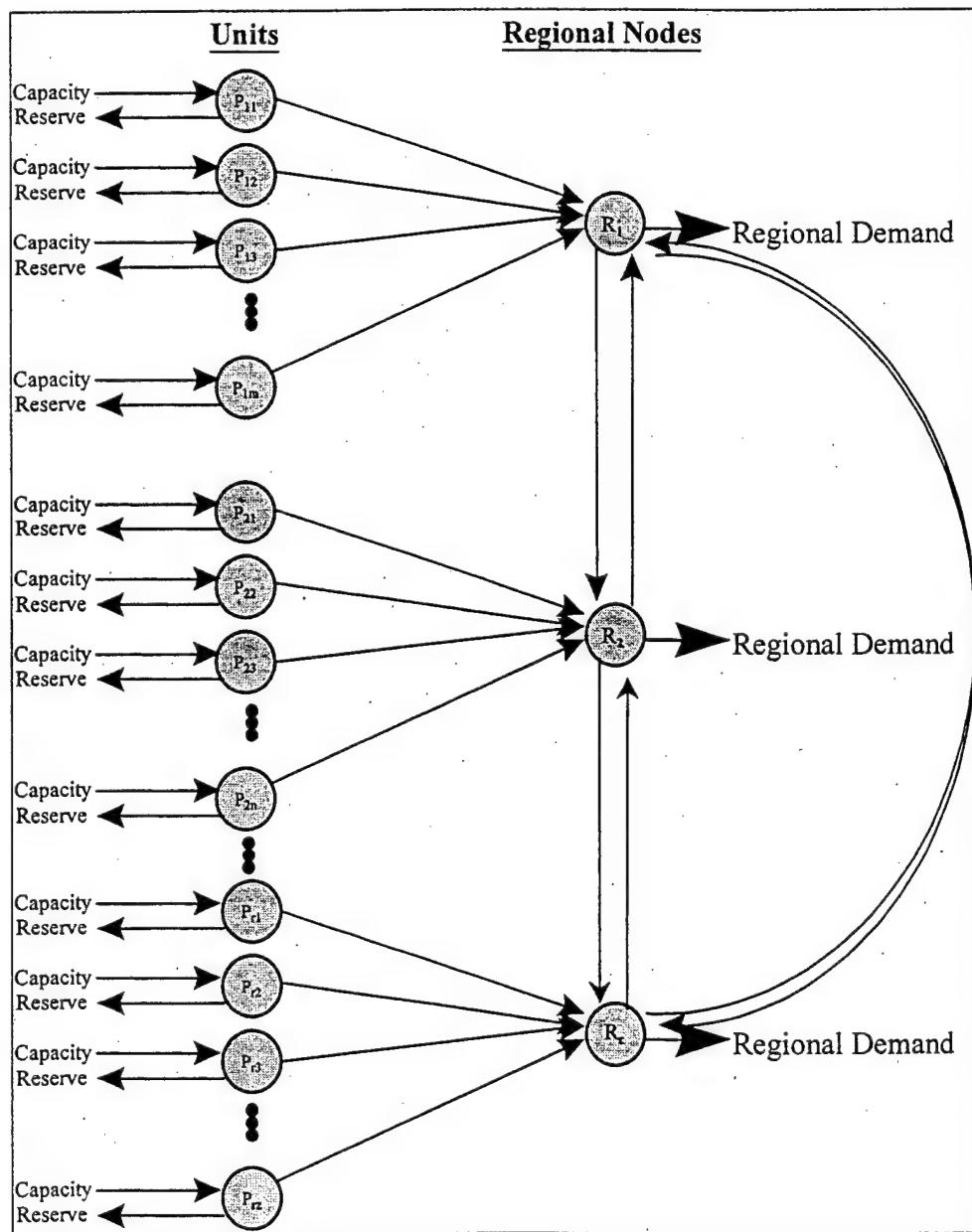


Figure 5. Network Representation of Perfect Competition Model

The mathematical formulation approximates perfect competition by modeling the economic dispatch of electricity. The linear programming model and a description of the objective function and each constraint follows the introduction of the indices, data, variables, and output.

#### Indices:

<i>i</i>	generating units
<i>j, k</i>	regions
<i>l</i>	firms

#### Given Data:

$C_{ijl}$	constant marginal cost of unit <i>i</i> in region <i>j</i> owned by firm <i>l</i>
$CAP_{ijl}$	capacity of unit <i>i</i> in region <i>j</i> owned by firm <i>l</i>
$TLOSS$	percentage loss incurred over transmission lines between regions
$LOSS$	percentage loss incurred over transmission and distribution lines within a region
$DEM_j$	demand in region <i>j</i>
$RES\_RATIO$	required reserve ratio for the area
$FOR_{ijl}$	Forced Outage Rate for unit <i>i</i> in region <i>j</i> owned by firm <i>l</i>
$TCAP_{jk}$	transmission capacity from region <i>j</i> to region <i>k</i>

#### Decision Variables:

$x_{ijl}$	megawatts (MW) of electricity generated by unit <i>i</i> in region <i>j</i> owned by firm <i>l</i>
$xr_{ijl}$	MW of capacity required for reserves by unit <i>i</i> in region <i>j</i> owned by firm <i>l</i>
$y_{jk}$	MW of electricity transmitted from region <i>j</i> to region <i>k</i>

#### Output:

$z$	total variable cost of meeting demand
-----	---------------------------------------

$$\text{Minimize: } z = \sum_i \sum_j \sum_l C_{ijl} x_{ijl} \quad (4.1)$$

Subject To:

$$\sum_i \sum_j (x_{ijl} - RES\_RATIO \cdot x_{ijl}) \geq 0 \quad \forall l \quad (4.2)$$

$$x_{ijl} + xr_{ijl} = CAP_{ijl} \cdot (1 - FOR_{ijl}) \quad \forall i, j, l \quad (4.3)$$

$$y_{jk} \leq TCAP_{jk} \quad \forall j, k, \text{ where } j \neq k \quad (4.4)$$

$$\begin{aligned} & \sum_i \sum_l (x_{ijl} \cdot (1 - LOSS)) + \sum_k (y_{kj} \cdot (1 - TLOSS)) \\ & - \sum_k y_{jk} = DEM_j \quad \forall j \end{aligned} \quad (4.5)$$

$$x_{ijl}, xr_{ijl}, y_{jk} \geq 0 \quad \forall i, j, k \quad (4.6)$$

The objective function, Equation (4.1), computes the total variable cost by summing costs across all units, regions and firms. Since this is a short-run model, implying that capacity investment decisions have already been made, only the variable costs are included. Variable costs are determined for each unit by multiplying the unit specific marginal cost ( $C_{ijl}$ ) by the output of each unit ( $x_{ijl}$ ). Each unit is assumed to have a constant marginal cost that includes the projected fuel costs and the variable operating and maintenance (O&M) costs. When the marginal cost curves for all the units are added together, a stepped supply function similar to the supply function in Figure 3 is created.

The objective function results in the economic dispatch across all regions, and thus approximates the perfectly competitive solution for meeting demand.

The reserve ratio constraints, Equation (4.2), require each firm to maintain a spinning reserve to satisfy regional reliability requirements. Every firm that generates electricity is required to preserve capacity up to a percentage (*RES\_RATIO*) of electricity it generates.

The generation capacity constraints, Equation (4.3), ensure that the sum of the electricity produced by each unit ( $x_{ijl}$ ) and the capacity used as spinning reserve ( $xr_{ijl}$ ) is equal to the adjusted total capacity ( $CAP_{ijl}$ ) of the unit. Figure 5 represents this relationship with the arcs coming in and out of the node for each unit. To account for unscheduled maintenance and outages,  $CAP_{ijl}$  is adjusted to expected capacity by using the forced outage rate ( $FOR_{ijl}$ ) specific to that unit. The  $FOR_{ijl}$  represents the probability of an unplanned outage in any given hour for that unit. Scheduled maintenance is not included because its scheduling and duration can be a strategic decision. Under regulation, scheduled maintenance on a unit during peak demand is usually prevented. After restructuring, however, there will no longer be this control over scheduled maintenance. It could be advantageous for owners of multiple generating units to conduct scheduled maintenance on some of their units during periods of peak demand to decrease total capacity in the region and increase prices for their remaining units. This potential strategic behavior is not addressed in the model of perfect competition or the algorithm for imperfect competition.

Equation (4.4) represents the transmission capacity constraints. The transmission paths ( $y_{jk}$ ) are the flow of electricity between regions  $j$  and  $k$ . These flows are constrained to be less than or equal to the transmission capacity on the lines. Figure 5 depicts these paths with the arcs connecting the regional nodes.

Electricity has inelastic demand with elasticities much less than one in the short run. Long run elasticities, however, are closer to one (Joskow and Schmalensee 1983). Since this model is of the static economic dispatch of electricity, a perfectly inelastic demand curve is assumed for each hour. This means that the quantity demanded for the given hour will not change as price increases. In reality there can be load shedding during periods of high prices, however, this model does not capture this action.

The demand constraints, Equation (4.5), model the generation required to meet demand for each region by summing the total generation from units in that region ( $x_{ijl}$ ) plus the total generation imported into the region ( $y_{jk}$ ) minus the amount of local generation exported outside the region ( $y_{kj}$ ). This total must satisfy the demand for the region. The graphical representation of this constraint in Figure 5 is similar to that of the generation capacity constraint. The arcs coming into and out of each regional node represent the flow of electricity for that region. During transmission over long distances, some amount of electricity is dissipated as heat (Borenstein and Bushnell 1999). There are also losses when power is “stepped up” and “stepped down” during the delivery of electricity (Fox-Penner 1998). These losses are accounted for by adjusting the amount of electricity produced by each generating unit by a loss factor ( $LOSS$ ) and by adjusting

electricity flowing between regions with additional losses ( $TLOSS$ ) in Equation (4.5).

The last constraints, Equation (4.6), ensure that all variables are non-negative. Imports and exports are handled by interchanging the subscripts  $j$  and  $k$ , allowing  $y$  to always remain positive.

This model of perfect competition is used to determine the economic dispatch of electricity for different levels of demand. By solving it for different levels of demand, the average perfectly competitive price of electricity is approximated for multiple regions. These prices are compared to the prices from the imperfect competition algorithm to analyze market power.

#### 4.2 Imperfect Competition Algorithm

The focus of this research is to analyze the effect of transmission on horizontal market power in the wholesale electricity generation industry. The algorithm that maximizes profits for a dominant generating firm in an electricity market with multiple regions is developed in this section. Two of the assumptions of perfect competition are that each firm is a price taker whose actions have no effect on market price and that there is free entry into the market. These assumptions are relaxed to look at imperfect competition.

The assumption that all firms are price takers may not be appropriate in a restructured electricity market. Given the existence of franchise monopolies under regulation, there is likely to be an incumbent firm with the market share to act as a

dominant firm and influence price. Alternatively, there may be several large firms, each having an influence on price; however, this research only models a single dominant firm. Firms would be able to enter the market over time and decrease the dominant firm's market share. However, the number of plants is fixed in the short run and the only entry into the market is through transmission. If the transmission grid did not have capacity limitations, the market power of the dominant firm would decrease due to the relatively free entry of generation from the surrounding regions. Since the transmission grid does have capacity limitations, congestion can limit short-run entry for some levels of demand, thus increasing the dominant firm's market power.

The effect of transmission on a dominant firm's profit maximizing solution is demonstrated in Figure 6 using a two-region market. As in the example in Figure 4, it is assumed that there exists a single transmission line connecting the two regions and that the supply and residual demand curves are linear. Region 1 consists of a perfectly inelastic demand, dominant firm supply, and fringe supply, but region 2 only has fringe supply with no demand. For illustrative purposes, figure 6 indicates differences in the cost of supply for the region 1 fringe, the region 2 fringe, and the dominant firm, but in reality, the costs have approximately the same distribution. Figures 6a – 6c show the results for no transmission, unlimited transmission, and limited transmission between the regions, respectively. With no transmission (Figure 6a) the dominant firm maximizes profits by producing where its marginal revenue equals its marginal cost ( $MR_{df} = MC_{df}$ ). The resulting price ( $P_1$ ) is determined by the residual demand curve ( $D_R$ ).

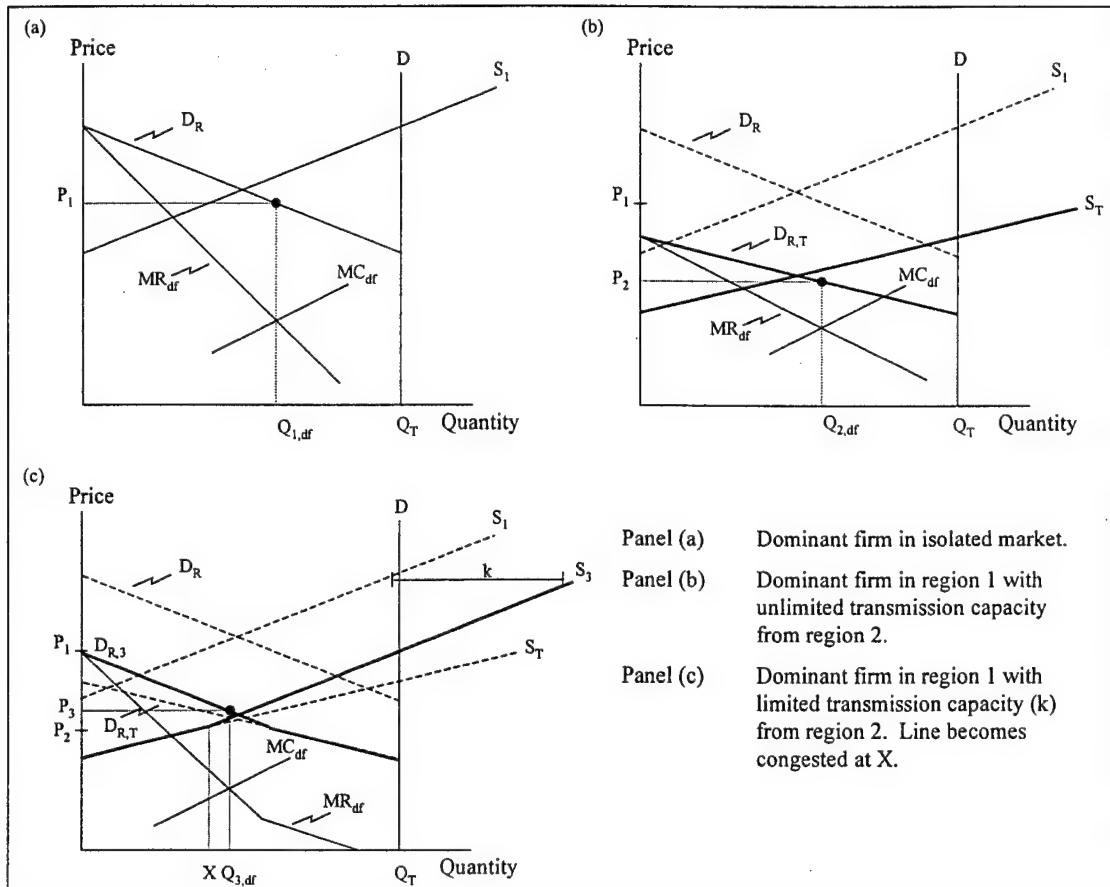


Figure 6. Transmission Effect in Two-Region Imperfect Competition Example

Figure 6b shows how this result changes when the transmission line between the two regions has an unlimited capacity. The fringe capacity from region 2 shifts the fringe supply curve to  $S_T$  which also shifts the residual demand to  $D_{R,T}$ . The marginal revenue curve for the dominant firm also shifts and intersects  $MC_{df}$  at  $Q_{2,df}$ . The quantity produced by the dominant firm does not change a great deal from Figure 6a, but the price ( $P_2$ ) decreases significantly. The dominant firm still receives a price greater than its marginal cost, but the entry of new fringe supply limits its market power and its profits.

The third scenario, where transmission capacity ( $k$ ) becomes congested at a total of  $X$  megawatts, is depicted in Figure 6c. When transmission becomes congested, the fringe supply curve shifts because it no longer includes the fringe supply from region 2. This portion of the supply curve has the same slope as the fringe supply curve in Figure 6a, but is shifted horizontally by the amount of fringe supply being imported from region 2, or the capacity of the transmission line ( $k$ ). This break in the new fringe supply curve ( $S_3$ ) results in a similar break in the new residual demand curve ( $D_{R,3}$ ). With a shift up in  $D_{R,3}$ , the dominant firm in region 1 can receive a higher price ( $P_3$ ) for each megawatt of generation.

More realistically, there would exist demand in both regions and the dominant firm might have resources in both regions. If the dominant firm has resources in region 2, it may have an incentive to increase output in region 2 at some levels of demand to congest the transmission line into region 1, even if it means producing at a loss in region 2. When the increased profits in the isolated region are greater than the losses it may incur in the surrounding regions, this becomes an optimal strategy for the dominant firm.

This example is just one of the many possible outcomes. Another possibility not addressed is that the fringe might be unable to meet demand on its own. If this is the case, the fringe supply curve becomes vertical prior to meeting demand. This causes the residual demand curve also to become vertical, resulting in the dominant firm acting as a monopolist facing a perfectly inelastic demand curve. The dominant firm would have the ability to reduce output and raise price to an infinite level.

Determining the equilibrium also becomes more difficult when there are more than two regions and multiple transmission paths between regions. Even though this example is simplistic, it shows that a dominant firm may act strategically to congest transmission into a region so it can benefit from increased prices in the isolated region.

#### 4.2.1 Non-Linear Programming Model for Maximizing Profits

The perfect competition model uses linear programming to minimize costs across all generating units. An equivalent formulation would be to maximize profits across firms since all firms are assumed to be price takers. Since this assumption is relaxed and the dominant firm can influence prices, prices are no longer exogenous in the profit maximization formulation of imperfect competition:

$$\text{Maximize: } \pi_{df} = \sum_i \sum_j (P_j(\cdot) - C_{ij,df}) \cdot x_{ij,df} \quad (4.7)$$

Subject To: Equations (4.2)–(4.6).

In this formulation, the profits of the dominant firm ( $\pi_{df}$ ) are maximized subject to the same constraints as in the model of perfect competition. The price in each region ( $P_j(\cdot)$ ) is a function of the quantity produced in that region and the quantity being imported from other regions, introducing non-linearity into the model. This non-linearity creates computational difficulty, especially for large problems. The next section formulates an

algorithm to approximate this formulation while avoiding the difficulty of solving a large non-linear programming problem.

#### 4.2.2 Profit Maximization Algorithm

Rather than solve the profit maximization problem in Equation (4.7), the cost minimization problem from Equations (4.1)–(4.6) is solved iteratively at different levels of production by the dominant firm. To capture potential strategic action by the dominant firm, the quantities produced in each region are varied so that all combinations of generation by the dominant firm across regions are evaluated. The dominant firm's profit is estimated for each solution. The combination that produces the highest profit is the optimal strategy for the dominant firm.

Estimating profit requires the determination of price in each region. Duality theory allows the shadow price on the demand constraint (Equation 4.5) for each region ( $j$ ) to be used as the price ( $P_j$ ) of generation. The shadow price is the marginal cost of the marginal unit, or the generating unit that would be forced to produce if an extra unit of demand existed in that region. The shadow price automatically adjusts for the assumed losses in transmission and distribution. When all firms bid marginal costs, the marginal unit is determined by the economic dispatch of generation. In the dominant firm price-leadership model, the dominant firm acts strategically to force a higher cost fringe unit to be on the margin. The dominant firm achieves this in one of three ways: 1) not bidding units into the power pool, or capacity withholding, 2) bidding above marginal costs on

units so that they are not dispatched, or 3) operating at a loss in one region to congest transmission lines and isolate another region. The first two strategies result in fewer dominant firm generating units being dispatched and a higher cost fringe unit on the margin. The third strategy results in the dominant firm producing more than it should in one region, and withholding capacity in another region. To produce more than it should, the dominant firm would have to bid below marginal cost on some units which would result in generating units operating with marginal costs above the regional price. The formulation of the problem as a linear programming model allows prices to be determined for each of these scenarios by using the shadow price on the demand constraints.

As mentioned in the previous section, the dominant firm has monopoly power over any demand that cannot be met by the fringe. Given the assumption of perfectly inelastic demand, economic theory says a monopolist can charge an infinite price. To prevent this from occurring, an additional generation unit is added in each region with a marginal cost equal to an arbitrary high price. This assumed "maximum" price limits the price markup by the dominant firm. An algorithm tying together these different concepts is now introduced.

Indices:

$i$	generating units
$j$	regions
$df$	dominant firm

Given Data:

$C_{ij,df}$	marginal cost of unit $i$ in region $j$ owned by the dominant firm $df$
$QMAX_{df,j}$	total dominant firm $df$ capacity in region $j$
$LP$	min cost model, Equations (4.1)–(4.6), with the added constraints:

$$\sum_i x_{ij,df} \leq Q_{df,j} \quad \forall j \quad (4.8)$$

$\delta$	incremental decrease of capacity used to loop through dominant firm generation in each region $j$
$Q_{df,j}$	amount of generation by dominant firm $df$ in region $j$ for each run of $LP$

Decision Variables:

$x_{ij,df}$	megawatts (MW) of electricity generated by plant $i$ in region $j$ owned by the dominant firm $df$
-------------	--

Output:

$P_j$	price in region $j$ from $LP$ ; shadow price on demand constraint from $LP$
$\pi_{df}$	profit for dominant firm $df$ for a given iteration
$BEST\_PROFIT$	best profit of dominant firm across all iterations
$BEST\_Q1$	quantity produced in region 1 resulting in $BEST\_PROFIT$
$BEST\_Q2$	quantity produced in region 2 resulting in $BEST\_PROFIT$

The list of indices, data, and variables for this algorithm repeats some terms used in the linear programming model of the perfectly competitive solution in Section 4.1 and introduces some new terms. The pseudo-code for the algorithm to estimate market power for a dominant firm is presented in Figure 7. The algorithm is condensed for

```

 $Q_{df,1} = Q_{MAX_{df,1}}$ 
 $BEST\_PROFIT = 0$ 
WHILE  $Q_{df,1} \geq 0$ 
   $Q_{df,2} = Q_{MAX_{df,2}}$ 
  WHILE  $Q_{df,2} \geq 0$ 
    Run LP
     $\pi_{df} = \sum_i \sum_j (P_j - C_{ij, df}) \cdot x_{ij, df}$ 
    IF  $\pi_{df} > BEST\_PROFIT$  THEN
       $BEST\_PROFIT = \pi_{df}$ 
       $BEST\_Q1 = Q_{df,1}$ 
       $BEST\_Q2 = Q_{df,2}$ 
    END IF
     $Q_{df,2} = Q_{df,2} - \delta$ 
  END WHILE
   $Q_{df,1} = Q_{df,1} - \delta$ 
END WHILE

```

Figure 7. Algorithm to Estimate a Dominant Firm's Market Power

presentation. For example, this representation of the algorithm only allows the dominant firm to own assets in two regions. The complete GAMS code for the application of this algorithm to Colorado is in Appendix A.

The algorithm iterates through different levels of dominant firm production in each region by varying  $Q_{df,j}$  by a predetermined amount ( $\delta$ ) using WHILE loops. For each feasible solution of the LP, price is determined for every region ( $P_j$ ). After the  $P_j$ s are determined, the total profit for the dominant firm ( $\pi_{df}$ ) is computed by summing profits across all regions. If this profit is greater than the previous best profit, it is stored as  $BEST\_PROFIT$  and the quantities are stored as  $BEST\_Q1$  and  $BEST\_Q2$ . The algorithm then reduces  $Q_{df,2}$  by  $\delta$  and goes through the process of computing  $\pi_{df}$  for this

new combination. The process is repeated until all combinations of  $Q_{dfj}$  have been evaluated. The combination resulting in the largest profit is the dominant firm's optimal production strategy for the given level of demand.

This algorithm approximates the non-linear profit maximization problem in Equation (4.7) by iteratively solving the perfect competition model. As with the perfect competition model, this algorithm can be solved for different levels of demand to estimate the price of electricity for a region facing market power by a dominant firm. By comparing these prices to those from the perfect competition model, the magnitude of market power is measured using the Price-Cost Margin Index (PCMI). The transmission capacities are also varied to analyze the effect of transmission on the prices and market power. Other mitigation strategies such as promoting entry into the market by new generation firms, divesting the dominant firm's assets, and limiting capacity withholding of the dominant firm are analyzed by changing the inputs and assumptions of this model. These alternatives are explored in Chapter 7, the public policy analysis for Colorado's electricity industry.

## Chapter 5

### COLORADO'S ELECTRICITY INDUSTRY

The model for perfect competition and algorithm for imperfect competition formulated in the previous chapter are used to study market power issues in Colorado's electricity industry. This chapter introduces Colorado's electricity industry by providing background information on the industry and a detailed description of the data used in this analysis. The chapter concludes by providing details of the application of the general model to the specifics of Colorado.

#### 5.1 Background

Colorado's electricity industry is currently regulated, but like many other states, Colorado is considering the possibility of restructuring. In 1998, a broad-based 30-member Electricity Advisory Panel was created by the Colorado General Assembly (Senate Bill 98-152) to determine whether restructuring of the electricity industry is in the best interest of Colorado electricity consumers and the state as a whole. The panel members were appointed to represent the different stakeholders in Colorado's electricity industry. After fifteen months and over thirty meetings where they listened to expert testimony and debated the issues, the Panel voted 17-12 that restructuring is not in the best interest of Colorado. Two major concerns for those who voted against restructuring

are the fear of increased electricity rates and the potential market power of Public Service Company of Colorado (PSCo), which controls almost two-thirds of the electricity generation available in the State of Colorado. The fear of increased rates stemmed not only from market power issues, but also on Colorado's status as a low-cost state prior to restructuring (Colorado Electricity Advisory Panel 1999). Because the 17-12 vote did not constitute the two-thirds majority that the Legislature requires as a formal recommendation and due to the continued restructuring activities of other states in the region, restructuring is still debated in Colorado. The remainder of this section addresses Colorado's electricity industry in more detail.

### 5.1.1 Location

The Colorado electricity industry cannot be studied in isolation because it is part of the Rocky Mountain Power Area (RMPA) and the Western System Coordinating Council (WSCC). The WSCC covers all the contiguous states west of the Rocky Mountains, British Columbia and Alberta in Canada, and portions of northern Mexico. The RMPA is a smaller region in the WSCC that includes Colorado and eastern Wyoming (Figure 8). The WSCC includes a large number of investor-owned and municipal utilities and encompasses an area of nearly 1.8 million square miles of highly interconnected transmission network, known as the Western Interconnection. The companies in this region operate as part of a single synchronized network. Only small interconnections connect the WSCC with the two other synchronized systems operating

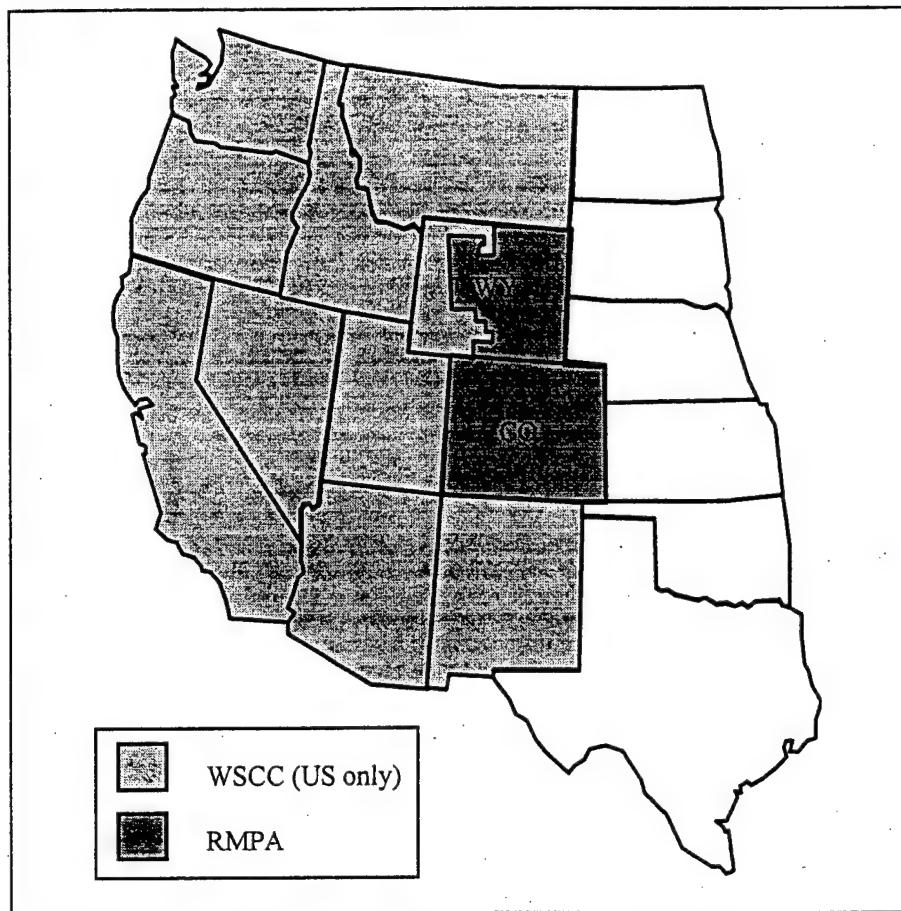


Figure 8. WSCC and RMPA

in the United States, the Eastern Interconnection and the Texas Interconnection (Bailey 1998; Deb, Albert, and Hsue 1996). Because it is located on the eastern edge of the WSCC, Colorado can be isolated when its limited transmission capacity for imports becomes congested. The entire WSCC needs to be modeled to account for the excess capacity from the surrounding regions that is available to be imported into Colorado.

### 5.1.2 Transmission

Colorado connects to the rest of the WSCC with transmission lines between Wyoming and eastern Colorado, the Four Corners region and western Colorado, and Utah and western Colorado. Since most of Colorado's demand is in eastern Colorado, the primary concern is transmission into eastern Colorado. In addition to the connection with Wyoming (which has an upper limit of 1,424 MW), there is a major transmission line connecting eastern and western Colorado with an upper limit of 1,675 MW (Sweetser 1998a). All power flowing into eastern Colorado must be imported through one of these major transmission lines. When both of these lines are congested, the eastern Colorado electricity market is isolated from the rest of the WSCC.

### 5.1.3 Demand

As mentioned previously, the majority of Colorado's demand is in eastern Colorado. Population is concentrated in the metropolitan areas of Greeley, Fort Collins, Boulder, Denver, Colorado Springs, and Pueblo east of the Rocky Mountains. As can be seen in Table 1, nearly 90% of Colorado's 1995 total demand was in eastern Colorado

Table 1. Colorado's Distribution of Demand in 1995

Region	Total 1995 Net Energy Sales (GWh)	% of Colorado Net Energy Sales
Western Colorado	3,680,552	10.4%
Eastern Colorado	31,636,267	89.6%

(EIA 1996, 165). This concentration of demand, combined with the fact that much of the generation is located close to the low-cost fuel sources in western Colorado and Wyoming, magnifies the importance of transmission into eastern Colorado.

#### 5.1.4 Supply

The ownership of generation in Colorado includes two investor-owned utilities, twenty-six Rural Electric Cooperatives, twenty-nine municipal utilities, and three joint action agencies (Sweetser 1998a). In 1996, 73% of Colorado's generation capacity came from coal-fired generating units that are very inexpensive because of their proximity to "low-sulfur" coal fields. Hydroelectric dams accounted for 16.4% of the total capacity in the region in 1996 (Feiler, Rabago, and Wang 1999). These low-cost generation resources and the absence of nuclear generation result in rates below the national average for Colorado's electricity customers. In 1998, the average revenue per kilowatt-hour for the United States was 6.75 cents while Colorado's average was only 6.0 cents. However, Colorado had the fourth highest average revenue per kilowatt-hour of the eleven states in the WSCC (EIA 1998).

The market share of the largest investor-owned utility in Colorado, Public Service Company of Colorado (PSCo), causes concern in a restructured Colorado electricity industry for market power and an increase in already low rates. In 1998, PSCo controlled 75% of generation in eastern Colorado and 45% in the RMPA (Sweetser 1998a). PSCo became part of the holding company New Century Energies through a merger with the

Amarillo-based Southwestern Public Service Company and Cheyenne Light, Fuel and Power in 1995. A merger with Northern States Power Company from Minneapolis has recently been approved, demonstrating New Century Energies' desire to continue to expand. Without transmission connecting Colorado with the demand regions for Southwestern Public Service Company and Northern State Power Company, these mergers should minimally affect market power in the short-run dispatch of generation. However, the effect of these mergers should be considered in an analysis of market power over the long run.

## 5.2 Data

To study market power in Colorado, data are required for the entire WSCC. A database developed by Henwood Energy Services, Inc. (HESI) and licensed for use by the Colorado Public Utilities Commission (PUC) is the primary source of data in this research. This research models 2005 as a target year for restructuring in Colorado. This section outlines how data from the HESI database and other sources are organized into a year 2005 database.

### 5.2.1 Transmission Data

In its work for the State of Colorado, Stone and Webster Management Consultants also used the database developed by HESI. To integrate the HESI database into their analysis of the entire WSCC, Stone and Webster developed a transmission

topology that divides the WSCC into twelve transmission areas (Figure 9). Each transmission area has internal transmission constraints, but they are considered small enough to be ignored. The topology follows a well-defined set of transfer limits for the WSCC known as Path Ratings or Tot Limits. These transfer limits represent the total transfer capability under first contingency planning conditions, referred to as First Contingency Total Transfer Capability (FCTTC) (Stone and Webster Management Consultants 1999). This transmission topology is also used in this research for estimating market power in eastern Colorado with the focus on transmission into eastern Colorado from western Colorado and the Northeast (the shaded regions in Figure 9).

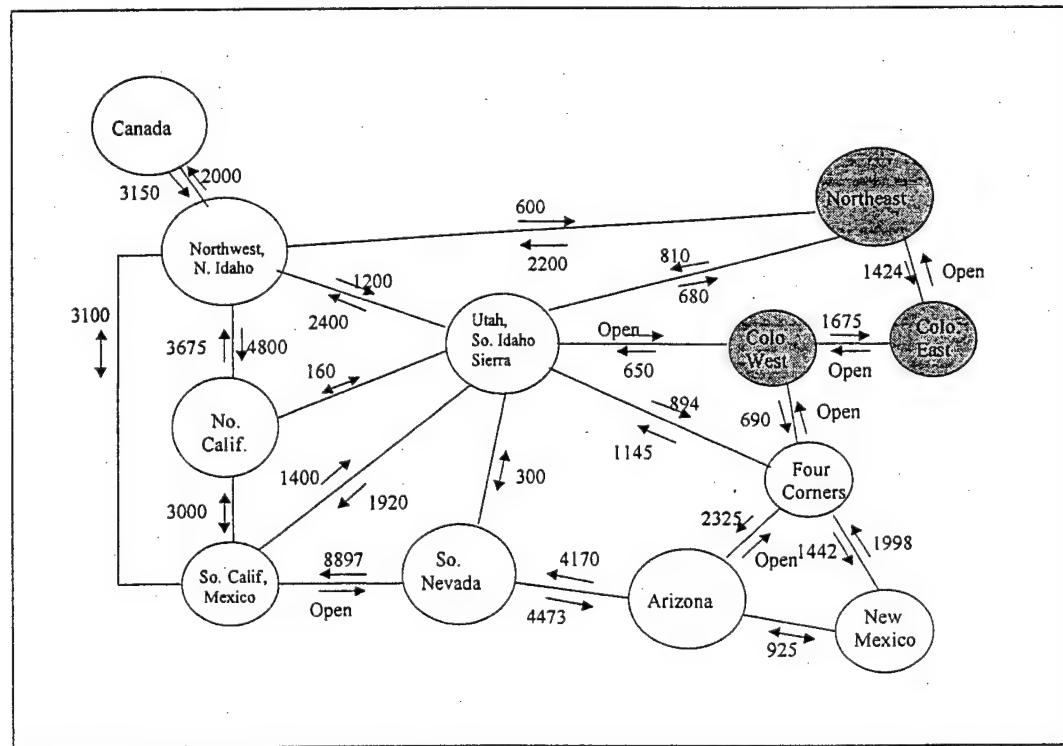


Figure 9. WSCC Transmission Topology and Path Limits

### 5.2.2 Supply Data

The HESI database contains capacity and cost information for 1,580 generating units in the WSCC. Once the generating units are assigned to their appropriate regions, or transmission areas from Figure 9, and the cost and capacity information are computed and adjusted for 2005, supply curves can be developed for each of the regions.

The variable costs and capacity data for each unit are extracted from the HESI database. The capacity data come from the maximum rating of each unit and the variable costs consist of variable operating and maintenance (O&M) and fuel costs. Equation (5.1) shows how total variable costs are computed:

$$\text{Variable Cost (\$/MWh)} = VOMC + \frac{(FP + TC) \cdot HR}{1000} \quad (5.1)$$

where:

<i>VOMC</i>	variable O&M costs specific for each unit (\$/MWh)
<i>FP</i>	fuel price specific for each fuel type (\$/MMBtu)
<i>TC</i>	fuel transport cost specific for each fuel type (\$/MMBtu)
<i>HR</i>	heat rate specific for each generating unit (btu/kWh)

The HESI database does most of the cost calculations including adjustments for inflation and forecasts of fuel prices for the year 2005, but the individual cost data can also be found in the database.

The data for Colorado and PSCo are checked for consistency with other sources since the emphasis of this research is PSCo's ability to exercise market power in Colorado. The sources used for comparison are the Stone and Webster (1999) report, Sweetser's (1998a) analysis of market power in Colorado, and the PSCo's 1999 Integrated Resource Plan (IRP) (1999). The primary checks performed are on ownership and capacity of each generation unit. Because the key is the control of each generation unit, the long-run contracts PSCo has with other utilities are also considered. Costs are not reviewed as closely because Sweetser's study is the only other source for costs. Sweetser also uses variable O&M and fuel costs to approximate total variable costs. However, his data came from a variety of different sources and were not adjusted for inflation or projected changes in fuel prices. The costs computed with the HESI database do make these adjustments and are all from a single source, so they are not adjusted to reflect Sweetser's costs. The capacities and ownership map very closely across all data sources. Most changes made to the HESI database for this research come directly from the PSCo IRP. For example, ownership of some units are adjusted due to contracts expiring or plants being retired prior to 2005 and to account for existing power purchase contracts. The IRP also has planned investments by PSCo prior to 2005.

A primary concern for Colorado is the market share owned by PSCo in 2005. Table 2 shows the forecasted 2005 market share for PSCo assuming no divestiture is required as part of the restructuring process. PSCo also controls another 175 MW of capacity in the Northeast that is not shown in Table 2. This market share is slightly lower

Table 2. PSCo's 2005 Market Share in Colorado

Region	PSCo 2005 Capacity (MW)	Total 2005 Capacity (MW)	PSCo Market Share
Eastern Colorado	4,669.00	7,076.60	66.0%
Western Colorado	444.50	2,601.50	17.1%
Colorado Total	5,113.50	9,678.10	52.8%

than the percentage PSCo now controls. The difference is due to the assumption that expired generating contracts are not renewed. This assumption is reasonable since PSCo is aware that its market share is a concern and it has indicated a willingness to lower its market share. The real concern is the market share in eastern Colorado since PSCo can act strategically to congest transmission and isolate eastern Colorado from the rest of the RMPA and WSCC. PSCo's market share is much smaller and less of a problem as the market expands to include the RMPA and WSCC. The data for individual generating units are used for western Colorado, eastern Colorado, and the Northeast since these are the regions with PSCo owned units.

The entire WSCC is included in the model so the excess capacity available to compete in Colorado across the transmission lines can be estimated. The individual generating units for the WSCC regions without PSCo generating units are aggregated according to variable costs to approximate their regional supply curves. Grouping generation units by variable costs reduces the number of units and still provides good approximations of the regional supply curves. By approximating the supply curves with

fewer units, the number of variables and the run times for the linear programming model are significantly reduced with very little impact on the results.

The batch version of the  $K$ -means clustering algorithm is used to cluster generating units by variable costs (Bishop 1995, 187). Mathematically, the algorithm seeks to partition the generation units into  $K$  disjoint subsets  $S_j$  containing  $N_j$  units, in order to minimize the sum-of-squares clustering function given by:

$$J = \sum_{j=1}^K \sum_{n \in S_j} \|x^n - \mu_j\|^2 \quad (5.2)$$

where there are  $N$  units  $x^n$  in total, and the goal is to find a set of  $K$  representative vectors  $\mu_j$  where  $j = 1, \dots, K$  and

$$\mu_j = \frac{1}{N_j} \sum_{n \in S_j} x^n \quad (5.3)$$

The batch version of this algorithm randomly assigns generating units to clusters, computes the mean variable cost for each new cluster of units, and then reassigns units to the cluster with the closest mean. Means for each cluster are then recomputed and units are reassigned again. This process continues until there are no units that need to be moved into a new cluster. The clusters of generating units resulting from this process can

be viewed as generic generating units with a capacity equal to the sum of all units in the cluster and variable cost equal to the mean variable cost for the cluster.

One drawback to using the *K*-means clustering algorithm is that this type of iterative clustering technique is especially sensitive to initial starting conditions (Bradley and Fayyad 1998). Therefore, rather than randomly assigning units to mean vectors, a "smarter," reproducible initial assignment of generating units to clusters is used. The generating units in each region are sorted by cost to find the biggest differences in variable costs (cost deltas) between adjacent units. The largest cost deltas are used as the break points for the initial assignment of units to mean vectors, or clusters. The batch version of the *K*-means clustering algorithm is then applied to this initial assignment of units. Figure 10 shows the result of applying this algorithm to northern California. The 327 actual generating units in this region are reduced to twelve generic units, or clusters. The supply curves from the aggregated and raw data practically lie on top of one another. Therefore, this approximation does not lose much of the information from the actual supply curve while it reduces the number of units and the number of variables in the linear programming model. Similar results are achieved for the other regions using roughly the same number of generic units, but southern California and Northwest require extra units to better approximate the curvature of their supply curves from the raw data. No attempt is made to optimize the number of units needed to approximate these regions. Generic units are added until most of the curvature in the actual data is approximated.

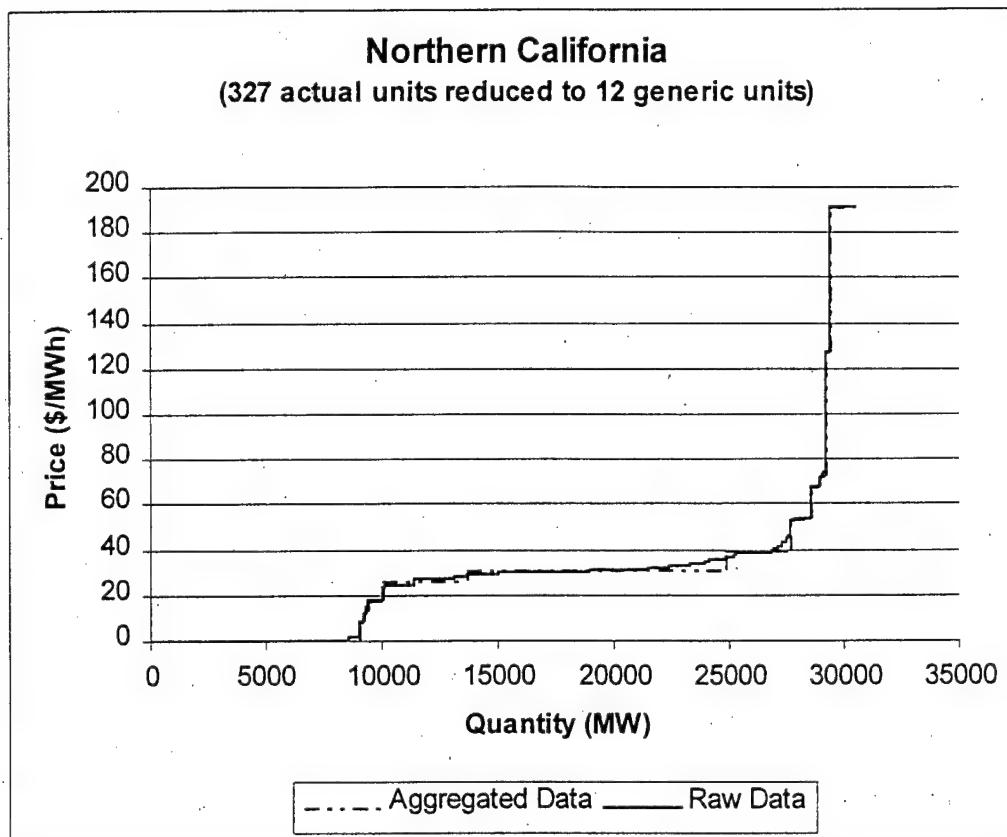


Figure 10. Regional Supply Curve

Twenty-six generic units are used to capture southern California's 359 original units and fifteen generic units are used to capture the Northwest's 230 original units.

By aggregating generating units in all regions except western Colorado, eastern Colorado, and the Northeast, the total number of units are reduced from 1,580 to 297. The final set of aggregated generation units along with their capacities, variable costs, and forced outage rates is in Appendix B.

### 5.2.3 Demand Data

Peak demand is forecasted for Colorado in 2005 using the HESI database. The database estimates peak demand by month and July is projected to have the highest peak demand in Colorado in 2005. The projected peak demands are 7,723 MW for eastern Colorado and 792 MW for western Colorado, for a total of 8,515 MW. Since the peak for Colorado is forecasted to be in July, the July 2005 peak demands are also forecasted for the other regions even though July is not be the month with the highest peak demand for all regions.

The model developed in this research is static, thus only runs for "snapshots" of demand. Levels of demand other than just peak need to be modeled to analyze market power in Colorado. The 1996 load duration curve for the RMPA (Sweetser 1998a) is used to represent the shape of the load duration curve for all regions. Annual load duration curves sort hourly load data from largest load (peak demand) to the smallest load for that year. To approximate the 1996 RMPA load duration curve, it is segmented into thirteen sections where each section represents an equal amount of load, but a different probability of occurrence. Figure 11 shows the actual load duration curve for the RMPA in 1996 and the approximation of the load duration curve.

By assuming that a load duration curve for any region at any given time period has an identical shape to the 1996 RMPA load duration curve, approximations can be made for each region in July 2005. Table 3 shows the generalization of the approximated load duration curve in Figure 11. Instead of hours and load (as in the axes in Figure 11),

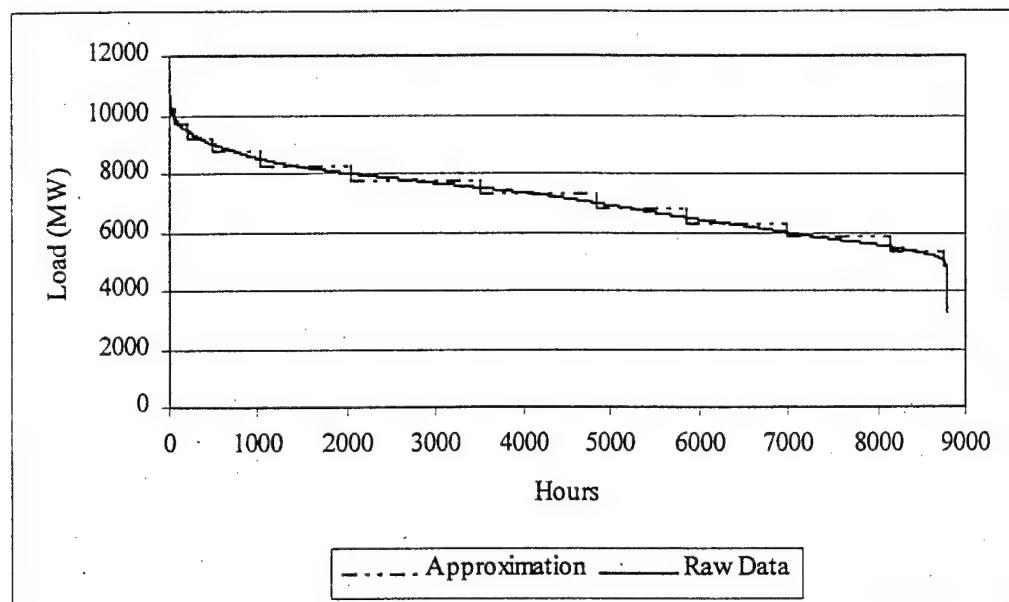


Figure 11. 1996 RMPA Load Duration Curve

Table 3. Load Duration Curve Data

Demand Level	1	2	3	4	5	6	7
% of Peak Demand	100.0%	95.5%	90.9%	86.4%	81.8%	77.3%	72.7%
Probability	0.1%	0.4%	1.6%	3.4%	6.2%	11.3%	16.8%
Cumulative Probability	0.1%	0.5%	2.1%	5.5%	11.7%	23.0%	39.8%
Demand Level	8	9	10	11	12	13	
% of Peak Demand	68.2%	63.6%	59.1%	54.6%	50.0%	45.5%	
Probability	15.1%	11.7%	12.7%	13.3%	7.0%	0.4%	
Cumulative Probability	54.9%	66.6%	79.3%	92.6%	99.6%	100.0%	

the table has the percentage of peak demand and its associated probability of occurrence. Each set of these data points represents a step in the approximation of the load duration curve. Using this table and the estimated July 2005 peak demands, thirteen different levels of demand are computed for each region. Prices and market power are examined by running the model for each of these thirteen levels of demand. The probabilities are also used to estimate average prices and markups.

### 5.3 Application of the Algorithm to Colorado

This section describes the application of the general algorithm developed in Chapter 4 to Colorado's electricity industry. First, the perfect competition model (Equations 4.1 – 4.6) is applied to Colorado. The resulting indices have 53 generating units (all 297 total units are captured using these indices), 12 regions, and 21 firms. The given data  $C_{ijl}$ ,  $CAP_{ijl}$ ,  $DEM_j$ ,  $FOR_{ijl}$ , and  $TCAP_{jk}$  all come from the database and are described in Section 5.2. The  $LOSS$  parameter is assumed to be 5% for all plants and  $TLOSS$  is assumed to be 2% for transmission between regions. These values are estimated by reviewing annual reports from utilities to the Colorado PUC and are consistent with the transmission loss assumptions made by Borenstein and Bushnell (1999). This study uses a  $RES\_RATIO$  of 7%, which approximates the current spinning reserve requirement in the WSCC (WSCC 1998).

The expansion of the model results in 13,390 equations, 26,857 variables, and 67,281 non-zero elements, but the size can be reduced significantly with some

preprocessing. Due to the construct of the indices and the different number of generating units each firm owns in each region, many imaginary units are created to fill out the constraint matrix. For example, PSCo owns 53 generating units in eastern Colorado. The non-zero elements of the model include 53 generating units for each firm in each region. With the aggregation of generating units, no other firm has 53 actual units in a region. Therefore, many of the "non-zero elements" represent non-existent generating units. By substituting these elements out of the problem, the model is reduced to 323 equations, 619 variables, and only 1,748 non-zero elements.

The model assumes a joint dispatch of all resources in the WSCC. Simulations of very large regions such as the WSCC have shown that the assumption of region-wide joint dispatch only results in a few percent reduction in dispatch costs, even assuming transmission capacity is costless and infinite (Graves et al. 1998). Because actual dispatch is fairly efficient, the assumption of joint dispatch should not bias the results significantly.

All generating units other than those controlled by PSCo are assumed to be part of the competitive fringe, so they must bid their marginal costs. Although this assumption should hold true in Colorado and the RMPA, other regions of the WSCC may also experience price markups due to strategic behavior by firms in those regions. If this assumption were relaxed, the higher prices in other regions would reduce some of the excess capacity available to compete in Colorado and could increase market power in

Colorado. Capturing the strategic activity across the entire WSCC is outside the scope of this model.

PSCo controls generating units in the eastern Colorado, western Colorado, and the Northeast, so the algorithm for imperfect competition must loop across PSCo capacity in all of these regions. The incremental decrease of capacity ( $\delta$ ) used to loop through dominant firm generation in each region is 100 MW. The maximum price used to prevent infinite markups in periods in which PSCo has local monopoly power is \$200/MWh and sensitivity runs are made on this assumption. To solve for the imperfect competition solution for all thirteen levels of demand, the perfect competition model iterates through 8,218 feasible combinations of PSCo production. The algorithm selects from these feasible solutions the PSCo generation combination that maximizes short-run profits for each level of demand.

## Chapter 6

### RESULTS

This chapter divides the results into two sections: a general analysis of market power in Colorado and the effect of transmission on market power.

#### 6.1 Market Power Analysis

To analyze market power in Colorado, the results from the approximation of perfect competition are first reviewed. These results are compared to previous studies of market power in Colorado. The imperfect competition results are then examined, highlighting the differences from the previous studies. Comparing the perfect and imperfect competition results allows for the market power analysis.

##### 6.1.1 Perfectly Competitive Results

The analysis of the perfect competition results, or baseline case, begins with an observation of the entire WSCC. Figure 12 shows the prices and movement of electricity in the WSCC during the projected peak demand in July 2005. It shows the lowest prices in the Northwest, highlighted by the fact that all transmission coming out of the Northwest is congested. Prices are very similar across the rest of the WSCC, with differences mainly due to transmission losses. For peak demand, eastern Colorado's

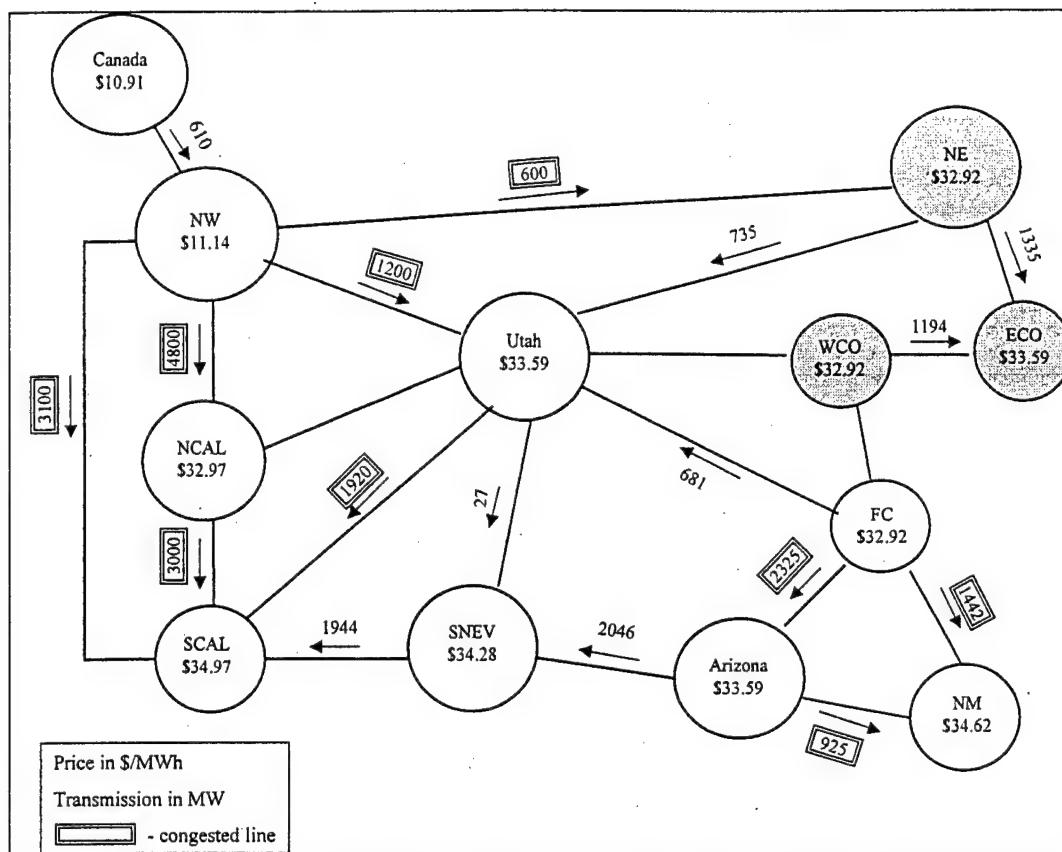


Figure 12. WSCC Perfect Competition Results for July 2005 Peak Demand

price (\$33.59/MWh) is tied as the fourth highest with three other regions. Southern California has the highest price at \$34.97/MWh. Transmission congestion is a problem into southern California and New Mexico due to their higher prices, but the rest of the transmission grid is uncongested. Even the transmission into eastern Colorado is not congested during peak demand. As excess capacity around the WSCC becomes available to compete during periods of less than peak demand, some of these other lines also become congested.

Figure 13 allows for a closer look at prices and transmission in eastern Colorado for all 13 periods of demand. The line and the right axis show the prices in ECO while the bars and the left axis show the use of the western Colorado-eastern Colorado (WCO-ECO) and the Northeast-eastern Colorado (NE-ECO) transmission lines for each level of demand. As expected, price decreases as demand decreases. Price is \$33.59/MWh at 100% peak demand and falls to \$12.16/MWh at the lowest level of demand, 45.4% of peak. Using the probability of each level of demand from Table 3, an average price of \$19.08/MWh is computed. Also from this graph, the movement of electricity into and out of Colorado is seen. Transmission is not congested at peak demand for either line, but the NE-ECO line does reach its maximum of 1,424 MW as more excess capacity

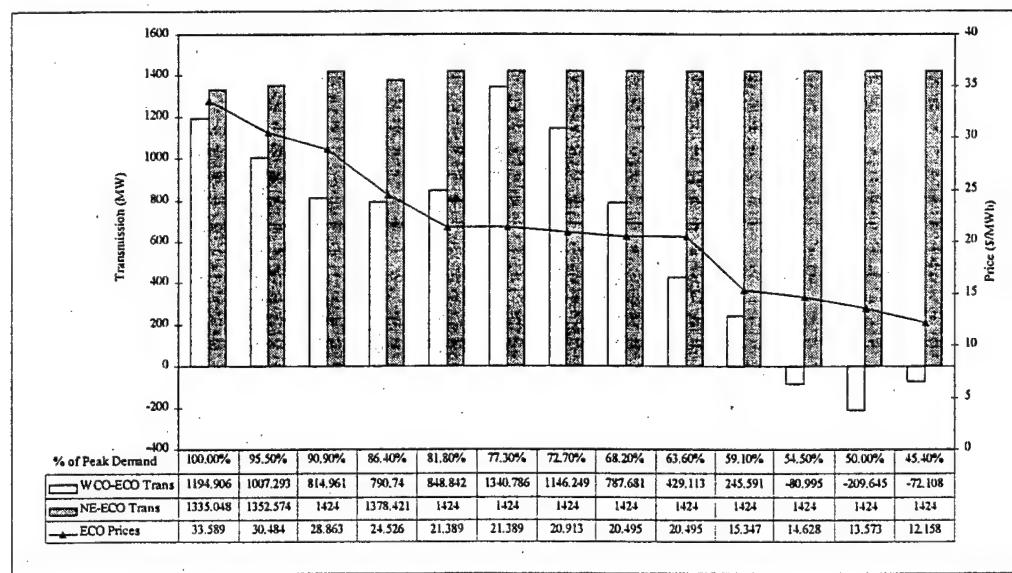


Figure 13. Transmission and ECO Prices for All Levels of Demand for Perfect Competition

becomes available to compete in Colorado. It stays congested for all levels of demand less than 86.4% of peak. Applying the probabilities from Table 3 again, this means that the NE-ECO line is congested over 95% of the time with the low-cost electricity being imported from the Northeast to the load centers in eastern Colorado.

In this scenario of perfect competition, the WCO-ECO transmission line never becomes congested. At the higher levels of demand, there is not enough excess capacity at a low enough price to compete in eastern Colorado. As demand drops and excess capacity increases, the line is used more until demand drops too low. At 54.5% of peak demand and lower (approximately 20% of the time), electricity is actually exported out of eastern Colorado. Prices are cheaper in eastern Colorado than in the surrounding regions at these low levels of demand, so the economic dispatch of generation sends the low-cost excess capacity out of eastern Colorado.

Prior to analyzing the imperfect competition scenario, the perfect competition results are compared to similar scenarios in the other studies of Colorado's electricity industry. Table 4 shows each study's predicted average wholesale price for electricity generation in eastern Colorado for the year 2005, except for the study performed for the Colorado Office of Consumer Counsel (OCC) which only models prices up to the year 2003 (Colorado Office of Consumer Counsel 1999; Stone and Webster Management Consultants 1999; Sweetser 1998a). Despite the different underlying assumptions, modeling techniques, and data, the prices are all fairly close except for the Stone and Webster study. In their simulation, Stone and Webster add extra costs to the bids of

Table 4. Comparison of Perfect Competition Prices

Model	Average Price in Eastern Colorado (\$/MWh)
Perfect Competition Scenario	\$19.08
Stone and Webster	\$29.10
Sweetser	\$20.71
Office of Consumer Counsel (2003)	\$18.25

variable O&M and fuel costs. They add an amount to cover start-up and shut-down costs if a unit is dispatched close to the margin and a wheeling charge if increased load would be met from the increase in generation of a unit in another region. Since the model developed in this research is static and only looks at dispatch for a given level of demand, it cannot capture the start-up and shut-down costs. Doing so would be an attempt to address dynamic competition in the electricity market, which is a notoriously difficult problem. Models attempting to solve the dynamic aspects of competition often yield indeterminate results (Borenstein and Bushnell 1999). Without knowing the magnitude of Stone and Webster's additions, it is assumed that they explain the differences in price between Stone and Webster and the other studies.

Another potential difference between the perfect competition prices from this study and the Stone and Webster study is the amount of reserves in the system. This research evaluates the short-run, static dispatch of generation and only includes a 7% spinning reserve requirement. The Stone and Webster study, however, is a dynamic model that includes investment and a capacity market for reserves. It results in a 21.8%

reserve margin for 2005 (Stone and Webster Management Consultants 1999). To determine how sensitive the model in this research is to a change in the reserve margin, the model is run changing the 7% spinning reserve margin to 21.8%. The surprising result is that there is little change in price with the increased reserve. The new average price is only \$19.99/MWh, with most of the change coming from peak demand. The reason for such a small change is that unused capacity satisfies the higher reserve requirement for periods of demand less than peak. Because higher prices at peak demand send a signal for investment, dynamic models looking at market power over time may be very sensitive to fluctuations in the required reserve margin. Since this research does not model investment and is not sensitive to changes in the spinning reserve requirement, the spinning reserve margin of 7% is used for the remainder of the runs.

#### 6.1.2 Imperfect Competition Results

As in the analysis of the perfect competition scenario, the analysis of the imperfect competition scenario begins with a look at the entire WSCC. Figure 14 shows the prices and movement of electricity across the WSCC during July 2005 peak demand for the dominant firm price-leadership scenario. When comparing these results to the perfect competition results in Figure 12, the first thing to notice is the new price of \$201.64/MWh in eastern Colorado. Both transmission lines into Colorado are now congested with lower cost generation competing in eastern Colorado to take advantage of the high price. In the perfect competition scenario, the transmission line from the Four

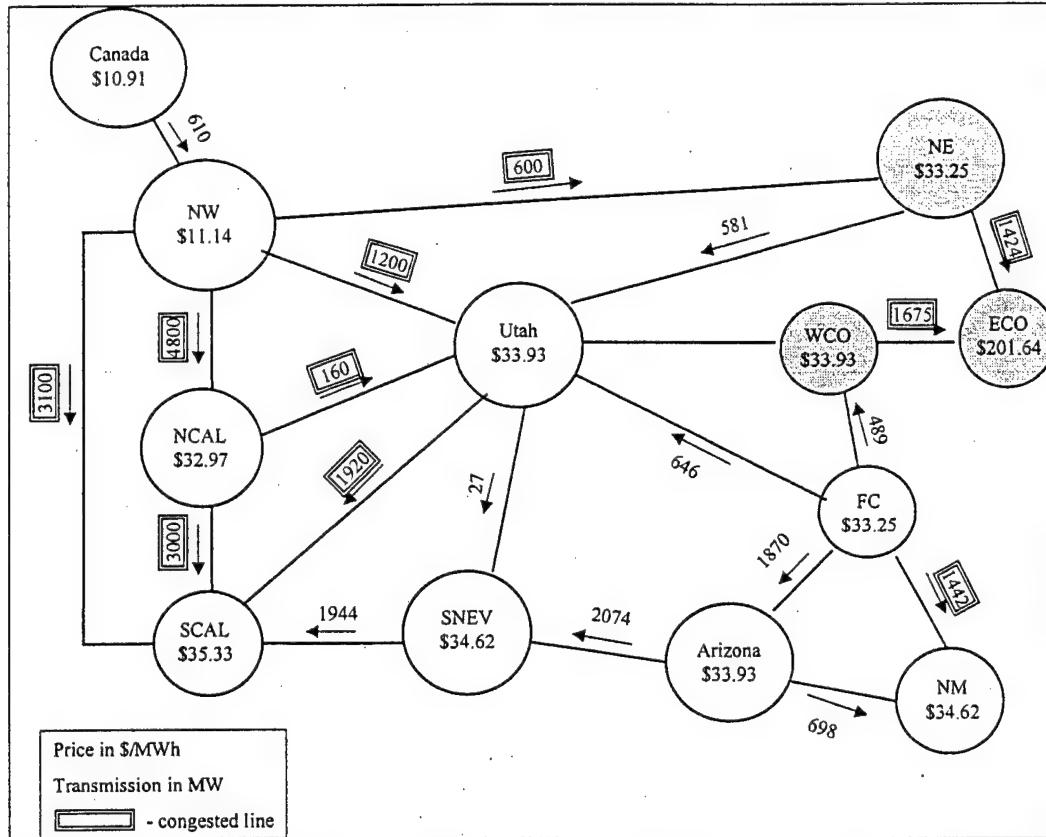


Figure 14. WSCC Imperfect Competition Results for July 2005 Peak Demand

Corners to Arizona was congested due to the higher prices in southern California and New Mexico. Some of that generation now flows through western Colorado to compete in eastern Colorado, relieving the congestion from the Four Corners to Arizona. For the rest of the WSCC, there are only slight differences in the prices and transmission patterns between the two scenarios. Once the transmission capacities into eastern Colorado become congested, the rest of the WSCC has an economic dispatch of generation very similar to the perfect competition scenario since the model ignores potential strategic behavior elsewhere.

The high price and congested transmission into eastern Colorado is not just a phenomenon of peak demand. Figure 15 shows the use of transmission (left axis) and price in eastern Colorado (right axis) for all thirteen levels of demand computed for the imperfect competition scenario. The NE-ECO transmission line is congested at every level of demand. The WCO-ECO transmission line is congested for the eight highest levels of demand, or 54.9% of the time. As can be seen in Figure 15, price corresponds to PSCo's ability to keep the line from western Colorado congested. As long as eastern Colorado is isolated from additional outside competition, PSCo can charge whatever price it desires.

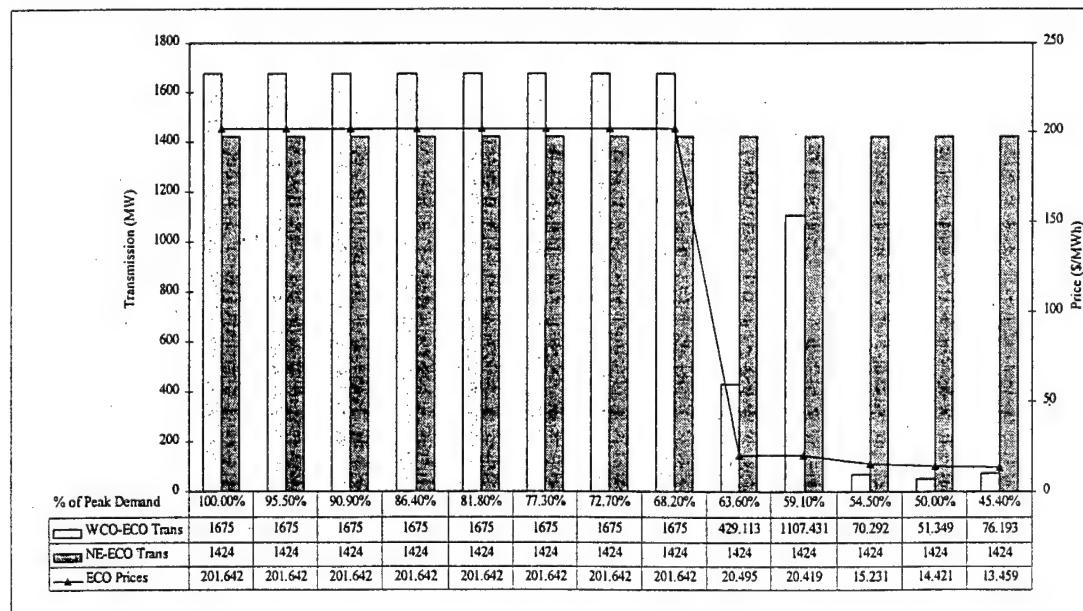


Figure 15. Transmission and ECO Prices for All Levels of Demand for Imperfect Competition

PSCo's strategic action in eastern Colorado dictates this dramatic increase in price. Figure 16 shows the contrast in PSCo's eastern Colorado production for the perfect and imperfect competition scenarios. PSCo is able to maintain its monopoly power over such a large percentage of the demand by reducing production well below the perfectly competitive levels. At 68.2% of peak demand, the last level of demand that PSCo is able to force congestion on both lines, PSCo is producing less than 10% of the amount it produces in the perfect competition scenario. PSCo loses its ability to congest the lines for demand less than 68.2% of peak because there is enough fringe capacity within eastern Colorado to meet the demand without PSCo producing at all. Figure 17 illustrates the impact PSCo can have on price by comparing the perfect and imperfect competition prices for each level of demand. Once PSCo is unable to keep the lines

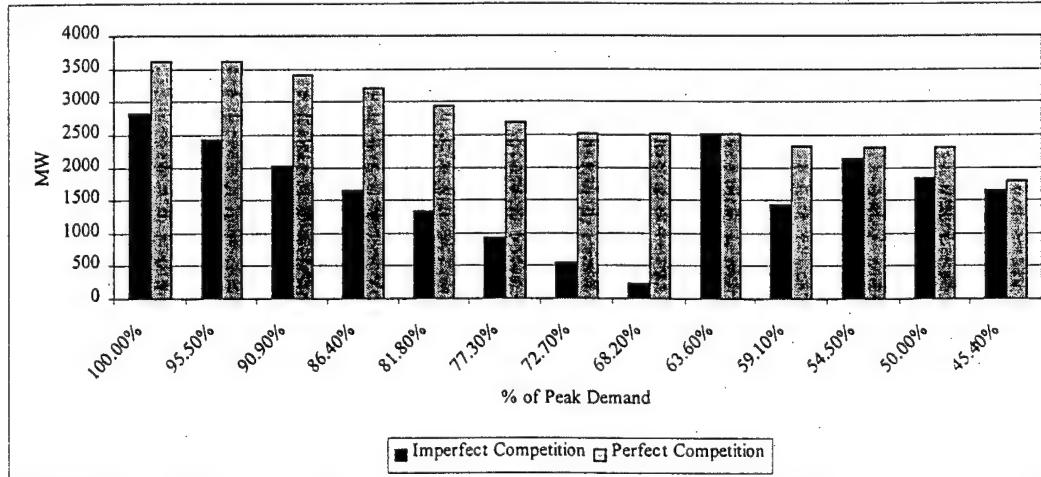


Figure 16. PSCo Production in Eastern Colorado

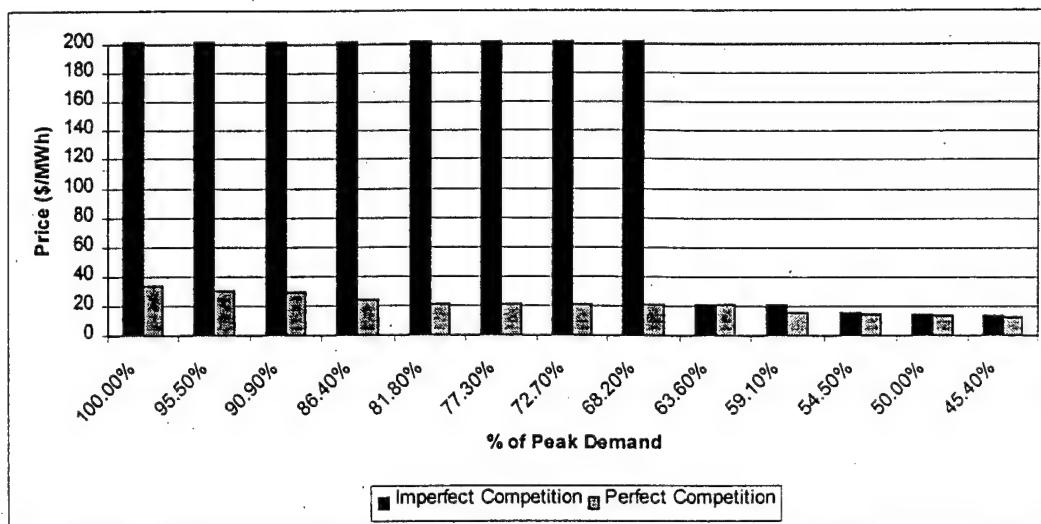


Figure 17. Eastern Colorado Prices

congested, the threat of entry across the WCO-ECO line keeps prices close to their perfectly competitive levels.

The resulting price of \$201.64/MWh shown in Figure 17 for demand levels greater than 63.6% of peak is not set by the generic plant with a cost of \$200/MWh used as an arbitrary price maximum. Instead, the generic interruptible load in the HESI database (\$191.56/MWh) is setting the price. After adjusting for the losses built into the model (*LOSS*), the resulting price is \$201.64/MWh. To get the maximum price (\$200/MWh before adjustment for losses), PSCo would have to reduce output even further for very little gain in price. Therefore, PSCo chooses to have the interruptible load be the marginal plant in the region and set the price. Since the price of the interruptible load is so close to the maximum price and due to the generic nature of the interruptible load, this price is also referred to as the maximum price in the analysis.

Additional runs are made to determine how sensitive the results are to the assumed maximum price of \$200/MWh. The model is run assuming maximum prices of \$1,000/MWh, \$500/MWh, and \$100/MWh. The percentage of time PSCo gets the maximum, or near maximum, price does not change at all with the maximum price at \$1,000/MWh or \$500/MWh. Of course the profits change as a result of the increased maximum price at the higher levels of demand, but PSCo cannot cut back its capacity any more during the lower periods of demand to take advantage of the higher maximum price. Reducing the maximum price to \$100/MWh does not affect the results significantly either. PSCo still obtains the maximum price for seven levels of demand, or 39.8% of the time. Since the results prove to be fairly insensitive to the assumed maximum price, \$200/MWh is used for the remainder of the scenarios.

In addition to being able to act as a monopolist facing an inelastic demand 54.9% of the time, PSCo also influences prices during the other periods of demand. The price markup for periods with less than maximum prices is measured using the Price-Cost Margin Index (PCMI), or  $\left( \frac{P - MC}{MC} \right)$ . As mentioned in Section 3.1, the PCMI is more convenient than the Lerner Index for comparisons across scenarios since it uses the same denominator in each scenario. The average PCMI for the lower demand periods when the price is no longer near the maximum is 11.6%. This shows that PSCo can still receive a significant markup over the perfectly competitive price even when it is not getting the maximum price.

These results all present the "worst case" scenario, a dominant firm maximizing short-run profits without fear of consequences. A dominant firm will actually choose a price that maximizes the sum of its discounted profits over time. This optimal price depends not only on how much the fringe can supply today, but also on the growth of the fringe over time. The higher the price is today, the faster the fringe grows and the faster the dominant firm's market share falls (Viscusi, Vernon, and Harrington 1998, 168). Therefore, PSCo would face repercussion if it dictates the maximum price for extended periods of time. The high prices will signal other firms to enter the market by building new generating units in eastern Colorado. PSCo could also lose its customers to other utilities if it forces such high prices. Many believe that having just been deregulated and allowed to compete, firms will also not risk being reregulated. As mentioned in the Section 3.2.1, Wolfram (1995) shows that firms in the British electricity spot market did not charge prices as high as previous models predicted they could have, possibly for the same reasons discussed here.

Because of this threat of repercussions, PSCo may not reduce its production from the perfectly competitive levels at such dramatic rates. To determine the impact of PSCo showing restraint in its strategic behavior and not exerting its full short-run market power, three scenarios are run assuming it only reduces its production to 10%, 25%, and 50% of the perfectly competitive level. Table 5 compares these capacity withholding scenarios to the unrestricted imperfect competition scenario. If it is assumed that PSCo never reduces its capacity by more than 25% of its perfect competition production, the

Table 5. Imperfect Competition with Capacity Withholding

	% of Time Max Markup	Avg PCMI for Other Periods
Imperfect Competition - Base Case	54.9%	11.6%
10% Capacity Withholding	0.0%	2.3%
25% Capacity Withholding	0.1%	4.3%
50% Capacity Withholding	11.7%	33.7%

threat of a maximum markup is almost non-existent. In addition to not achieving the maximum markup, the average PCMI is also below the 5% standard by the Department of Justice and Federal Trade Commission when capacity withholding is limited to 10% and 25%. At 50% capacity withholding, PSCo can still force the maximum markup 11.7% of the time, but enjoys a 33.7% average markup the rest of the time. Therefore, market power issues may not be as much of a concern if it is believed that PSCo will monitor its own action for fear of reregulation, entry into the market, or loss of customers. If the threat is not that strong, PSCo can still receive considerable markups without restricting its output by more than 50% of its perfectly competitive output.

An objective comparison of the imperfect competition results to the results in the other studies performed on Colorado is not attempted due to the different assumptions of the models and the fact that they use average price as a measure of market power. This research shows that average price is insignificant because there is no limit to the price PSCo charges 54.9% of the time. Therefore, more accurate measures of market power are the percentage of time the dominant firm is a local monopolist facing an inelastic

demand allowing it to set any price and the average PCMI for the periods without the maximum markup.

## 6.2 Effect of Transmission

As discussed in Section 3.2.2.2, firms view the transmission grid differently in a competitive industry than in a regulated industry. Because of increased regional trade, it is more likely for lines to become congested and for regions to become isolated. This can increase the market power for a dominant firm in the isolated region. Therefore, increasing transmission into a region, even if the added capacity is not utilized, may be beneficial in keeping prices closer to their competitive levels because of the threat of entry. Borenstein, Bushnell, and Stoft (1998) show that a “threshold” transmission capacity exists that integrates two markets connected by a transmission line. To analyze the effect of transmission on market power, the capacity of the WCO-ECO transmission line is varied so prices, PSCo production, the use of the line, and PSCo profits can be analyzed.

The imperfect competition model is solved iteratively, increasing capacity on the WCO-ECO transmission line by 100 MW increments up to 1,000 MW of added capacity. Table 6 compares the eastern Colorado prices from the base case of imperfect competition (no added transmission capacity) and the imperfect competition scenario with 1,000 MW of capacity added to the WCO-ECO transmission line.

Table 6. Comparison of Eastern Colorado Prices With and Without 1,000 MW of Added Transmission on WCO-ECO Line

% of Peak Demand	Cumulative Probability	Eastern Colorado Price (\$/MWh) Imperfect Competition (Base Case)	Eastern Colorado Price (\$/MWh) Added 1,000 MW on WCO-ECO Line
100.0%	0.1%	\$201.64	\$201.64
95.5%	0.5%	\$201.64	\$201.64
90.9%	2.1%	\$201.64	\$201.64
86.4%	5.5%	\$201.64	\$201.64
81.8%	11.7%	\$201.64	\$201.64
77.3%	23.0%	\$201.64	\$22.66
72.7%	39.8%	\$201.64	\$20.91
68.2%	54.9%	\$201.64	\$20.91
63.6%	66.6%	\$20.50	\$20.50
59.1%	79.3%	\$20.42	\$20.42
54.5%	92.6%	\$15.23	\$15.23
50.0%	99.6%	\$14.42	\$14.75
45.4%	100.0%	\$13.46	\$13.46

The effect that added transmission has on price and market power depends on the level of demand. At the highest levels of demand, increasing transmission has little effect on the outcome in eastern Colorado because there is no excess capacity in the surrounding regions to take advantage of the added transmission into eastern Colorado. With 1,000 MW of added transmission capacity on the WCO-ECO line, PSCo can still force the maximum price for all levels of demand above 77.3% of peak demand, or 11.7% of the time. Adding transmission capacity at the lower levels of demand does not reduce price either since the existing transmission capacity is already sufficient for integrating the regions for these levels of demand. For all periods of demand less than

68.2% of peak demand, or 45.1% of the time, adding 1,000 MW capacity to the WCO-ECO transmission line has no effect on the prices. For the periods of 77.3%, 72.7%, and 68.2% of peak demand, or 43.2% of the time, an additional 1,000 MW of transmission from western Colorado takes away PSCo's ability to congest the line and set the maximum price. The difference between these three different levels of demand is the amount of transmission required to discipline PSCo's behavior. A higher amount of transmission is required for 77.3% than for 68.2% of peak demand.

The remaining analysis of the effect of transmission on market power is performed on 72.7% of peak demand, but would be very similar for 77.3% and 68.2% of peak demand. Figure 18 shows the prices at 72.7% of peak demand for both perfect and

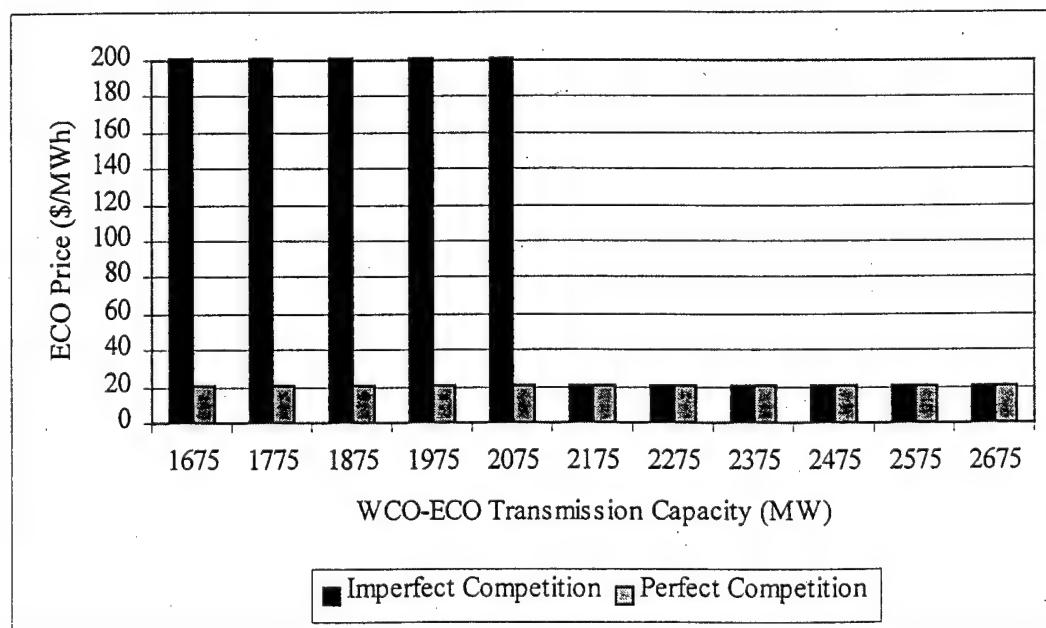


Figure 18. ECO Prices at 72.7% of Peak Demand

imperfect competition scenarios as transmission capacity is increased. PSCo can still force a price of \$201.64/MWh on eastern Colorado with 400 MW or less of added transmission capacity. With 500 MW or more of added transmission, the price reduces to the perfectly competitive levels.

PSCo is able to maintain its monopoly power by reducing its output in eastern Colorado to keep the transmission line congested. When transmission capacity is 2,075 MW, PSCo has to reduce its perfectly competitive level of production of 2,510 MW to only 140 MW to keep the line congested. Once it no longer has the ability to congest the transmission line, its production returns to the perfectly competitive level of 2,510 MW. As PSCo decreases production to keep the line congested, its profits also decline. Profits level off at the perfectly competitive level when production returns to the perfectly competitive level.

The result that is counterintuitive, but consistent with the research of Borenstein, Bushnell, and Stoft (1998), is that the use of the transmission line does not directly relate to the lower prices. When PSCo reduces its production to force higher prices, generation enters the market through transmission until the line is congested. Once PSCo loses the ability to keep the line congested and limit short-run entry into the market, there is relatively free entry into the eastern Colorado market and price returns back to the perfectly competitive price. The only cost of entry is the transmission loss. As price returns to its perfectly competitive level, so does the entry into the market, or usage of the transmission line. The added transmission capacity serves as a threat of entry to PSCo,

but the added capacity is not used once prices return to their perfectly competitive levels.

Figure 19 displays the use of the WCO-ECO transmission line as its capacity is increased. Up to a capacity of 2,075 MW, PSCo can keep the line congested and charge the maximum price. For capacity of 2,175 MW and higher, the threat of entry disciplines PSCo's strategic behavior. Adding 500 MW of transmission from western Colorado when it will not be used does not make much sense without an understanding of how the threat of entry disciplines the market. Somewhere between 2,075 MW and 2,175 MW is the "threshold" transmission capacity that integrates the western Colorado and eastern Colorado markets.

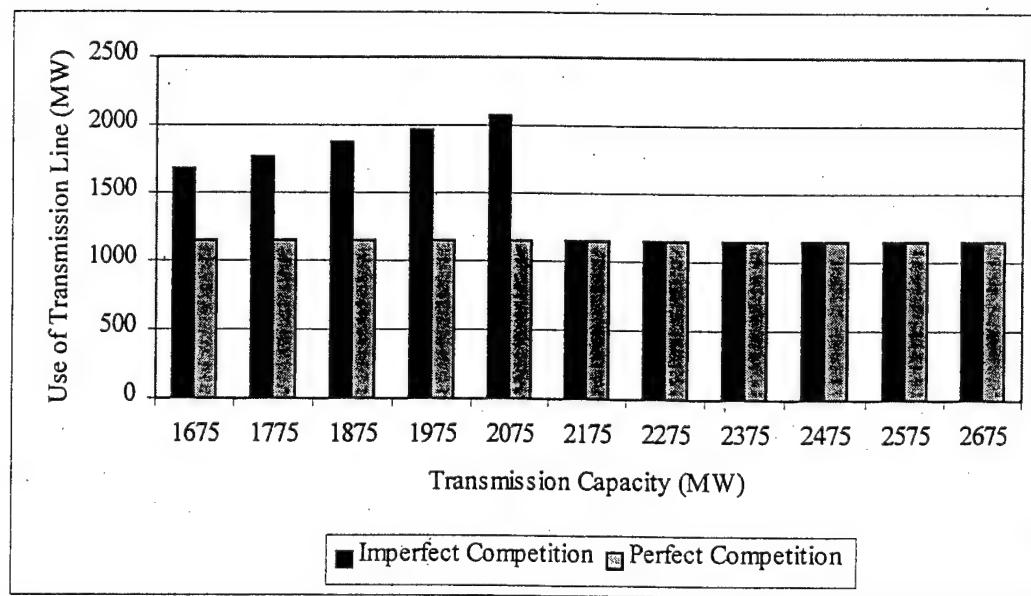


Figure 19. Use vs. Capacity of the WCO-ECO Transmission Line

Once the impact of additional transmission capacity and the threat of entry are understood, analyses can be performed to determine if the social benefit of additional capacity outweighs the cost of building new lines. This research does not perform a cost-benefit analysis, but the next chapter on policy analysis does discuss in more detail the effect of enhancing the transmission grid on market power.

The application of the model to Colorado did not prove to be a good case study for a generation firm to produce at a loss in one region to congest transmission so that higher profits can be made in another region as discussed in Cardell, Hitt, and Hogan (1997). There are a few reasons why this did not prove to be a good example. Even though PSCo has generation resources in multiple regions that would allow for this interaction, most of the capacity it controls is in eastern Colorado. Almost all the generation units that PSCo does own or control in western Colorado and the Northeast are low cost coal units. The marginal costs of these units are always below the regional price, so they are already operating at full capacity at all times. If it did control higher cost generation in the surrounding regions that would not be dispatched at some levels of demand in the perfect competition scenario, PSCo may have the incentive to operate these units at a loss in the imperfect competition scenario. If the extra generation from these units would congest the transmission into eastern Colorado for additional levels of demand, PSCo may be able to extend the period that it can force the maximum price. There may be regional markets that prove to be better examples of this behavior than Colorado, but it may also be more of a phenomenon of loop flow and its externalities.

Therefore, models such as the one developed by Cardell, Hitt, and Hogan (1997) that include the engineering complexity of the grid may have to be developed to capture this behavior.

This chapter applies the general model developed in this research to Colorado and the WSCC to measure market power in eastern Colorado and to show the importance of transmission on market power. By allowing competition from the surrounding regions and developing better measures for market power, this research provides a more accurate account of potential short-run market power in Colorado than previous research. The model demonstrates how PSCo can act strategically to congest the lines into eastern Colorado by including the transmission grid of the whole WSCC to allow for competition from the surrounding regions. The analysis also shows that increasing transmission into eastern Colorado limits PSCo's market power. These results support the research by Borenstein, Bushnell, and Stoft (1998) by validating that the threat of entry across the added transmission capacity rather than its actual use disciplines PSCo's strategic behavior.

## Chapter 7

### POLICY ANALYSIS

While the previous chapter demonstrates the value of the model developed in this research in measuring market power and capturing strategic effects of transmission in Colorado, this chapter uses the model to determine the effectiveness of market power mitigation strategies in Colorado. It investigates enhancing the transmission grid, promoting entry into the market, divesting PSCo generating units, and limiting capacity withholding as market power mitigation strategies. Combinations of these strategies are included to examine how they can be used together to limit PSCo's market power. The goals of these strategies are to reduce the percentage of time PSCo can achieve the maximum price and lower the average PCMI for the other periods of demand. This analysis provides insight for the policy makers in Colorado as they continue to consider restructuring the electricity industry.

#### 7.1 Increasing Transmission Capacity

The previous chapter shows how increased capacity on the WCO-ECO transmission line and the threat of entry forces PSCo to bid its generation units as it would in an economic dispatch of electricity, at least for some levels of demand. This section evaluates increasing transmission into eastern Colorado as a policy option. In

addition to further analysis of the WCO-ECO transmission line, enhancing the NE-ECO line is also considered.

Previous research on Colorado's electricity industry has either not put emphasis on the transmission grid or has provided misleading results about the effectiveness of added transmission on limiting market power. The report performed for the Colorado Office of Consumer Counsel (1999) lists alternatives for Colorado to consider in dealing with market power, one of which addresses transmission. The report suggests monitoring transmission closely to make sure no firm is exerting vertical market power by limiting access to the transmission lines and advocates increasing competition in the region by enhancing the transmission capacity into eastern Colorado. However, no analysis of the effectiveness of these strategies is performed. Although the Stone and Webster study (1999) addresses market power, it does not analyze or suggest mitigation strategies. They assume the transmission topology for the WSCC does not change over the seventeen-year horizon they model.

The only study that analyzes the policy of increasing the transmission line capacity into eastern Colorado is Sweetser (1998a). Sweetser concludes that relaxing the transmission constraints makes almost no difference in the portion of the year over which PSCo can apply a markup or in the magnitude of those markups. He acknowledges that he does not consider excess capacity from the surrounding regions, but claims that this should not matter due to the declining reserve margins in the WSCC. This claim holds true for periods of peak or near peak demand, but this research shows that there is excess

capacity to compete in eastern Colorado across the transmission lines for most levels of demand. This research is the first to quantify the benefits of increasing competition in eastern Colorado from surrounding regions through added transmission capacity.

The previous chapter shows that increasing the capacity of the WCO-ECO transmission line limits markups and returns prices closer to the perfectly competitive prices because of the threat of entry for some levels of demand. To further analyze the increase of transmission as a market power mitigation strategy, scenarios are run adding 500 MW and 1,000 MW of capacity to the transmission lines into eastern Colorado from western Colorado and the Northeast. Table 7 summarizes the effectiveness of these scenarios at limiting market power in terms of the percentage of time PSCo can force the maximum price and the average PCMI for the other periods of demand. An asterisk indicates that the policy also reduces the perfectly competitive price from the baseline perfectly competitive scenario because of more low-cost power being imported into

Table 7. Benefits from Additional Transmission into Eastern Colorado

	% of Time Max Markup	Avg PCMI for Other Periods
Imperfect Competition - Base Case	54.9%	11.6%
500 MW on WCO-ECO line	23.0%	7.2%
500 MW on NE-ECO line	23.0%	7.4%*
500 MW Combo (250 MW on both lines)	23.0%	8.4%*
1000 MW on WCO-ECO line	11.7%	7.1%
1000 MW on NE-ECO line	11.7%	6.4%*
1000 MW Combo (500 MW on both lines)	11.7%	6.4%*

Colorado. The largest decrease in the perfectly competitive price across all scenarios, however, is less than 2%. Increasing transmission capacity by 500 MW, regardless of which line's capacity is increased, reduces the percentage of time PSCo can force the maximum price to 23.0% and adding 1,000 MW of capacity reduces it to 11.7%. The average PCMI for the other periods are roughly 7% for all scenarios. This illustrates that increasing transmission capacity into eastern Colorado is effective in limiting market power.

The results in Table 7 demonstrate that the effectiveness of the policies does not depend on where the new capacity is added, only on the amount of capacity added. The slight decrease in the perfectly competitive price when capacity is added to the NE-ECO line is the only difference between the policies. This strategy decreases price because there is additional low-cost coal generation in Wyoming to import into eastern Colorado. In contrast, Chapter 6 shows that added capacity on the WCO-ECO line serves primarily as a threat of entry. Even though the price reductions are small when capacity is added to the NE-ECO line, the fact that the new transmission capacity will be used may be reason enough to increase transmission from the Northeast instead of from western Colorado. With more power being imported into eastern Colorado from the Northeast, less power has to be generated in eastern Colorado. This could also prove to be beneficial from an environmental standpoint by reducing air pollution in the populated areas of eastern Colorado. Although Colorado is narrowly complying with national air quality standards, revisions to the standards by the Environmental Protection Agency have made

compliance more difficult in the populated areas (Colorado Air Quality Control Commission 1999). Reducing power generation in eastern Colorado could help Colorado continue to meet the standards and avoid other costly pollution mitigation strategies. Another argument for investment in the NE-ECO line rather than the WCO-ECO line relates to the cost of building new lines. Building new transmission lines from Wyoming should be much less expensive than building lines over the Continental Divide from western Colorado. Given that the market power results show little difference between enhancing the WCO-ECO or the NE-ECO transmission lines, the above factors indicate that the best option might be to add capacity on the NE-ECO line.

Despite earlier claims by Sweetser (1998a), this analysis shows that increasing competition in eastern Colorado through the expansion of the transmission grid is an effective mitigation measure. The percentage of time PSCo can force the maximum price and the average PCMI for the other periods of demand can be significantly reduced with this strategy. The average markup is still above the 5% guideline by the Department of Justice and Federal Trade Commission, but it is approaching the levels of competition acceptable in most markets.

## 7.2 Entry of New Generation

Another strategy for mitigating market power is encouraging entry of new generation in eastern Colorado. Rather than introducing new competition from the surrounding regions through the transmission lines, competition in eastern Colorado can

be increased if fringe firms build new plants. To model entry, scenarios are run assuming an addition of 500 MW, 1,000 MW, and 1,200 MW of fringe capacity in eastern Colorado. The new generating units will not be fueled by coal since new coal plants are not being planned in this region for environmental reasons. Since most new investments and planned investments are natural gas, it is assumed that this new capacity comes from gas fueled generating units with variable costs of \$35/MWh.

The scenarios with 500 MW and 1,000 MW of entry have the same effect on the percentage of time PSCo gets the maximum price as the scenarios adding identical amounts of transmission capacity. This is expected since the percentage of time PSCo can dictate the maximum markup is purely a function of PSCo's market share as long as the maximum price is greater than the cost of any generating units. The transmission and entry scenarios allow for the same amount of competition in eastern Colorado, and thus reduce PSCo's market share the same amount. The percentage of time PSCo forces the maximum price is reduced from 54.9% to 23.0% with 500 MW of entry and to 11.7% with 1,000 MW of entry. However, the entry scenarios are not as effective at reducing the average PCMI for other periods of demand, resulting in 7.2% average markups for 500 MW of entry and 14.6% average markups for 1,000 MW of entry. The average PCMI is dependent on the cost of the generating units competing in the market. Transmission allows more low-cost coal generating units to compete in eastern Colorado instead of the more expensive gas generating units added in the entry scenarios.

A policy encouraging entry to mitigate market power should not be dismissed based on these results. As policy makers in Colorado consider their options for limiting market power, encouraging entry may prove to be a more viable option than building new transmission lines. In fact, PSCo has been mandated to acquire up to 1,200 MW of fringe generation in eastern Colorado (Colorado Public Utilities Commission 2000). Since this generation could be on the ground by 2005, another scenario looks at the impact of this amount of entry. PSCo receives the maximum price only 5.5% of the time and the average PCMI is 13.6% during the other periods of demand. While these results still indicate a degree of market power, they are an improvement over the 54.9% of the time PSCo gets the maximum markup and the 11.6% average PCMI for other periods in the imperfect competition base scenario.

### 7.3 Divestiture

Divestiture of assets by larger firms as a condition to recoup stranded costs has been a strategy used by several states restructuring their electricity industries. Announced divestiture plans by investor-owned utilities in 11 states indicate that more than 52 gigawatts of generating capacity was up for negotiated sales in 1998 (EIA 1998a). This research does not address the politics of achieving divestiture, but analyzes the effectiveness of divestiture as a market power mitigation tool in Colorado.

Divestiture is modeled using two approaches. The first approach divides control of each PSCo owned generating unit between PSCo and the competitive fringe. For

example, to model 50% divestiture, all PSCo owned units are divided with PSCo controlling half the capacity and the competitive fringe controlling the other half. This generic approach is used to analyze 50%, 25%, and 10% divestiture of PSCo-owned generating units. The other approach is to divest actual units. The following seven scenarios are analyzed:

1. Generic 10% divestiture
2. Generic 25% divestiture
3. Generic 50% divestiture
4. Divest Pawnee (\$11.06/MWh) – 9.7% of PSCo total capacity
5. Divest Ft. St. Vrain (\$20.33/MWh) – 13.8% of PSCo total capacity
6. Divest the new PSCo units expected before 2005 (\$35/MWh) – 10.9% of PSCo total capacity
7. Divest Pawnee (\$11.06/MWh) and Cherokee (\$12.1/MWh) – 23.3% of PSCo total capacity

The first three scenarios use the generic approach to divide the plants. Each of the next three scenarios selects plants from different regions of the supply curve to approximate the 10% generic divestiture. The final scenario approximates the 25% generic divestiture scenario with the divestiture of two generating units. Table 8 shows the results for each of these scenarios.

These results demonstrate that the ability to limit the percentage of time PSCo forces the maximum price depends only on the magnitude of the divestiture, not on which plants are divested. Divesting 10% lowers the percentage of time PSCo forces the maximum price to 23.0%, and divesting 25% lowers the percentage of time to 11.7%. If 50% of PSCo's assets are divested, the maximum price only occurs at peak demand, or only 0.5% of the time. The units taken away from PSCo do not matter from a policy

Table 8. Results for the Divestiture Scenarios

	% of Time Max Markup	Avg PCMI for Other Periods
Imperfect Competition - Base Case	54.9%	11.6%
1. Divest - Generic 10%	23.0%	7.2%
4. Divest - Pawnee (9.6%)	23.0%	7.2%
5. Divest - FSV (13.8%)	23.0%	7.2%
6. Divest - New (10.9%)	23.0%	6.8%
2. Divest - Generic 25%	11.7%	1.8%
7. Divest - Pawnee & Cherokee (23.3%)	11.7%	1.3%
3. Divest - Generic 50%	0.5%	1.2%

perspective since all generating units should be producing at full capacity when the assumed maximum price is greater than the cost of any of the units. Therefore, PSCo's total market share, regardless of the cost distribution of the units, is the determining factor on how often it can force the maximum price on eastern Colorado. The average PCMI is also only slightly sensitive to which plants are divested. However, PSCo's profits depend on the cost distribution of its generating units, so PSCo does care which plants are divested.

The effectiveness of 10% and 25% divestiture to reduce the percentage of time the maximum price prevails corresponds to the effectiveness of adding 500 MW and 1,000 MW of transmission capacity or new generation, respectively. The divestiture strategies, however, prove to be more effective in reducing the average PCMI for the other periods of demand. Therefore, the other mitigation strategies can be used to reduce

the maximum markups, but divestiture may be required to reduce markups for other periods of demand.

#### 7.4 Limits to Capacity Withholding

In the analysis of market power in Colorado in Chapter 6, it is shown that if PSCo monitors its own behavior to deter reregulation or long-run loss of market share, market power becomes less of an issue in the short run. The percentage of time PSCo can force the maximum price is reduced to 0.1% if it never produces less than 75% of what it would produce in the perfectly competitive dispatch of its generation units. With the same limit on capacity withholding, the average PCMI is 4.3%. If a policy can be developed to ensure PSCo limits its capacity withholding, these benefits do not have to be based on a belief that a long-run profit maximizing strategy designed to maintain market share will bring PSCo's production close to the perfect competition levels.

The purpose of this research is not to design policy, but a couple of alternatives to limit capacity withholding are introduced here. If there was a contract stating that a set of PSCo low-cost generation units would always be on, barring scheduled and unscheduled maintenance, PSCo's ability to reduce capacity would be limited. If any of these low-cost units were not bid into the power pool at a reasonable price, PSCo would be obligated to explain why or face the consequences laid out in the contract. Such a policy could be administered in a manner similar to how California administers their "must-take" resources. Unlike "must-run" generating units that are available to be dispatched

during certain hours to assure local reliability, "must-take" resources are dispatched whenever they are available (Jurewitz and Walther 1997). The cost of this policy includes the transaction cost of administering the contracts, but the policy could prove beneficial to efficient pricing in the market.

Another alternative is to monitor the operation of the competitive market in a manner similar to other regions that have restructured their electricity industry. For example, the Pennsylvania-New Jersey-Maryland (PJM) market has a Market Monitoring Unit that oversees the operation of the market and has the responsibility to monitor the potential of any market participant to exercise undue market power (PJM Interconnection 1998). The approximate costs and capacities of PSCo's generating units are known. Therefore, an agency monitoring the market would know which units should be operating at a given price. If an agency had authority to go back and review which units were dispatched for different hours, it would be able to approximate how much capacity PSCo was withholding during that hour. If it were determined to be more than the allowed limit, PSCo could be penalized. Such a policy would not require constant monitoring. Only when prices are suspiciously high would the agency need to review PSCo's production. If the penalty is severe enough and the chance of being caught great enough, the threat of being caught exceeding the capacity withholding limit could keep prices close to the perfect competition levels.

Any policy implemented to control PSCo's capacity withholding would require thorough analysis to make sure it has the desired effect. Introducing new policies may

create more problems than they solve. However, any policy that can be designed to limit capacity withholding by PSCo could prove to be the best mitigation strategy for reducing its ability to exercise market power in the short-run dispatch of electricity. But since the goal of restructuring is to move away from regulation, promoting competition is preferred.

### 7.5 Combined Strategies

The mitigation strategies discussed in sections 7.1 through 7.4 may be more effective at reducing PSCo's market power when they are combined and used together. It may also be more realistic to rely on a combination of strategies. For example, building new transmission into eastern Colorado proves to be one of the more effective policies, but it may not be realistic to build as much capacity as would be required. By combining the addition of a smaller amount of transmission capacity with another strategy, the same benefits might be gained as if a larger transmission investment was made.

With an additional 1,200 MW of fringe generation capacity planned to be built in Colorado prior to 2005, this scenario serves as the baseline for the analysis of combining strategies. An additional 500 MW of transmission capacity from the Northeast and 25% capacity withholding are combined individually and as a tandem with the 1,200 MW entry of generation. Section 7.2 shows that building new gas fueled generation units in eastern Colorado is not that effective in reducing the average PCMI for demand periods without the maximum markup. Therefore, adding 500 MW of transmission capacity

from the Northeast is considered since it allows more of the coal-fired generation in Wyoming to compete in eastern Colorado and can help reduce the average PCMI. Capacity withholding is selected because of its overall effectiveness, regardless of whether PSCo's long run strategy dictates less capacity withholding or if a policy is required to regulate PSCo's behavior.

Table 9 displays the results for these combined scenarios. The effectiveness of 1,200 MW of generation entry as a stand-alone policy has already been discussed in Section 7.2. With the addition of 25% capacity withholding, PSCo can no longer force the maximum price for any level of demand. PSCo can only force the maximum price 2.1% of the time when adding 500 MW of capacity to the NE-ECO transmission line is combined with the 1,200 MW of generation entry. Each of these scenarios also reduces the average PCMI below or close to the 5% competitive benchmark. The last scenario in Table 9, adding both of policies to 1,200 MW of generation entry, results in a near perfect competition outcome.

Table 9. Results for Combined Scenarios

	% of Time Max Markup	Avg PCMI for Other Periods
Imperfect Competition – Base Case	54.9%	11.6%
1,200 MW Entry	5.5%	13.6%
1,200 MW Entry/25% CW	0.0%	4.3%
1,200 MW Entry/500 MW NE	2.1%	8.2%
1,200 MW Entry/500 MW NE/25% CW	0.0%	4.0%

Other studies have discussed policy alternatives to mitigate market power, but still conclude that market power is a considerable problem in the short run in a restructured electricity industry (Colorado Office of Consumer Counsel 1999; Stone and Webster Management Consultants 1999; Sweetser 1998a). This research also indicates that market power is a significant problem given the existing structure of the industry in which PSCo controls over 65% of the generation capacity in eastern Colorado. However, the analysis shows that by increasing transmission capacity into eastern Colorado, promoting entry, divesting PSCo generation assets, limiting PSCo's capacity withholding, or implementing a combination of these policies, it may be possible to reduce the price markups to levels considered competitive by the Department of Justice and Federal Trade Commission. While this study only evaluates short-run markups, each of these mitigation strategies must be implemented over time. This magnifies the importance of performing analyses and making decisions now in order to positively influence the future structure of the electricity industry.

## Chapter 8

### CONCLUSIONS AND RECOMMENDATIONS FOR FUTURE WORK

This research develops an algorithm to approximate the non-linear profit maximization problem of a dominant firm in a regional electricity market. The model incorporates the transmission of electricity between regional nodes in a network representation of a transmission grid. The research demonstrates how transmission can integrate markets in the electricity industry and discipline the behavior of a dominant firm through the threat of entry from surrounding regions. Short-run market power by the dominant firm is measured by comparing results from the perfect and imperfect competition models.

Application of this algorithm illustrates that the dominant firm can have monopoly power over a portion of demand if it can isolate the market and force the competitive fringe to exhaust its generation capacity. With the inelastic nature of the demand for electricity, the dominant firm can set prices at any level it desires for these periods of demand. The model assumes a maximum price to limit markups for these levels of demand. Because the dominant firm has complete control over prices for some levels of demand, the use of average prices to determine market power has little meaning. This research develops a more accurate measure of market power for a dominant firm in the electricity industry. Rather than calculate average price over some period of time that

the dominant firm can set price at the maximum level, the percentage of time the dominant firm can act strategically to obtain the maximum price is approximated. For the other periods of demand, the average percent markup over the perfect competition price is used. These measures are used together to measure market power and to compare the effectiveness of mitigation strategies aimed at reducing market power.

The research applies the algorithm to Colorado's electricity industry. By modeling the entire Western Systems Coordinating Council (WSCC) to determine the levels of excess capacity in the surrounding regions available to compete in Colorado at different levels of demand, this research improves previous research of market power in Colorado. By not allowing competition from the surrounding regions, other research has overestimated the potential for market power in Colorado. For the base case scenario for imperfect competition, this research shows that Public Service Company of Colorado (PSCo) can set price at the maximum 54.9% of the time. For the remaining periods of demand, PSCo can still force an 11.6% average markup over the perfect competition price. This research shows significant market power for PSCo in the base case of imperfect competition, but also provides a framework for a comprehensive analysis of mitigation measures to reduce market power.

The analysis focuses on the effect of transmission on PSCo's ability to increase prices. The results show that if transmission into eastern Colorado is increased to the "threshold" capacity as it is defined in Borenstein, Bushnell, and Stoft (1998), the threat of entry will force price down to or near the perfect competition price. With 1,000 MW

of additional transmission capacity into eastern Colorado from western Colorado, the percentage of time PSCo can force the maximum price is reduced from 54.9% to 11.7% of the time. The added capacity on the line is not actually used; it is the threat of entry across these lines that disciplines PSCo's behavior.

In addition to increasing capacity on the transmission line from western Colorado, this research examines other mitigation strategies and their effectiveness on reducing PSCo's market power in eastern Colorado. The mitigation strategies analyzed include increasing transmission capacity into eastern Colorado from both western Colorado and Wyoming, promoting entry of new generation in eastern Colorado, divesting PSCo's generation assets, placing limits on PSCo's capacity withholding, and implementing a combination of these different strategies. The analysis shows that with the right action by policy makers, the potential for short-run market power in Colorado can be significantly reduced, if not eliminated. For example, with 1,200 MW of generation entry in Colorado, combined with a 25% limitation on PSCo's capacity withholding and an additional 500 MW of transmission into eastern Colorado from Wyoming, PSCo will no longer be able to force the maximum price, not even at peak demand. The average markup over the perfectly competitive price for this scenario is 4.0%, which is less than the 5% guideline used by the Department of Justice and Federal Trade Commission in their analysis of competition in markets. This does not imply that market power is not a concern in Colorado since the base case of imperfect competition still results in the maximum price 54.9% of the time and an 11.6% average price markup for the other

periods of demand. However, this research shows that effective policies can limit the short-run market power of PSCo if Colorado moves toward restructuring.

While this research compares the effectiveness of different mitigation policies at limiting market power in Colorado, this comparison could be improved by incorporating an analysis of the cost effectiveness of each strategy. Performing cost-benefit analyses could determine which strategy is the best alternative for policy makers. The analysis would require more detailed information on the actual implementation and costs of the policies.

Other research has shown that increasing responsiveness on the demand side also serves as an effective strategy to mitigate market power. The sensitivity of the results to increases in the elasticity of demand could not be analyzed because of the assumptions of this model. Increasing the responsiveness to price could potentially eliminate the dominant firm's ability to act as a monopolist with complete control over prices. By eliminating the extreme markups in price, the mitigation strategies analyzed in this research could be concentrated on reducing the markups that result from forcing higher cost fringe plants to be the marginal plants in the region. Additional research to incorporate demand-side management strategies into this model framework would be beneficial.

This research models only the short-run dispatch of electricity. Firms must also consider the dynamic aspect of running their generation facilities and the long-run implications of any behavior they choose in the short run. The short-run prices may

trigger entry into the market by new firms and investment in new generation capacity by existing firms. A dominant firm may behave strategically in the short run to limit entry into the market and loss of market share over a larger time horizon. Also, there are dynamic aspects of operating generating units that this research does not capture, such as start-up and shut-down costs. Expanding this research to incorporate these long-run and dynamic issues are additional areas for potential research.

In addition to analyzing demand side management strategies and looking at long-run and dynamic issues, there are other potential extensions of this model. This model only allows for a single firm with influence over price, but some regions have several strategic players. This model could easily be transferred to another region with a dominant firm, but would require modifications to be used in a market such as California with multiple large generation firms. To find the Cournot solution for multiple strategic players, loops could be added to the algorithm to vary production for each firm. Rather than searching for the maximum profit for the dominant firm, the resulting outcomes would have to be searched to find the combination resulting in a Nash equilibrium. A limitation to this approach would be the run time of the algorithm. As computer processing speeds continue to increase, this limitation will become less of a factor.

Another potential improvement to the model would be to increase the complexity of the grid. While explicitly modeling the grid for the whole WSCC to capture all aspects of the engineering complexity of the transmission of electricity is unrealistic, capturing some of the resulting externalities that result from the engineering complexity

at an aggregated level could improve the algorithm. Since loop flow allows power to travel instantaneously along all parallel transmission lines, increased congestion may occur on the grid. By ignoring the engineering complexity of the grid, this research may underestimate congestion on the grid and market power.

The focus of future research could be on looking at new issues rather than improving the algorithm since this research already improves other models of Colorado's electricity industry by allowing competition from the surrounding regions. For example, the model can be used to evaluate the benefits of new transmission lines connecting eastern Colorado with markets outside the WSCC. Since PSCo's holding company, New Century Energies, owns generation assets in Minnesota and Texas, this research extension could be very valuable to policy makers in Colorado. The effect of environmental policies, such as more stringent regulation of fossil fuel emissions, on the dispatch of electricity and electricity prices is another area for potential research. The model developed in this research has the flexibility to integrate these and other extensions to evaluate issues facing the electricity industry.

## REFERENCES CITED

Andersson, Bo and Lars Bergman. 1995. Market Structure and the Price of Electricity: An Ex Ante Analysis of the Deregulated Swedish Electricity Market. *The Energy Journal* 16, no. 2: 97-109.

Bailey, Elizabeth M. 1998. *The Geographic Expanse of the Market for Wholesale Electricity*. MIT Center for Energy and Environmental Policy Research.

Bakeman, Steven, Stephen Rassenti, and Vernon Smith. 1997. *Efficiency and Income Shares in High Demand Energy Networks: Who Receives the Congestion Rents When a Line Is Constrained?* University of Arizona: Economic Science Laboratory.

Bayless, Charles E. 1994. Less is More: Why Gas Turbines Will Transform Electric Utilities. *Public Utilities Fortnightly* 132 (December 1): 21-25.

Behling, B. N. 1938. *Competition and Monopoly in Public Utility Industries*. Urbana: University of Illinois Press.

Biewald, Bruce, Heidi Croll, and Richard Rosen. 1996. *Potential Costs and Benefits of Electric Industry Restructuring*. Boston: Tellus Institute.

Bishop, Christopher M. 1995. *Neural Networks for Pattern Recognition*. Oxford: Oxford University Press.

Borenstein, Severin and James Bushnell. 1999. An Empirical Analysis of the Potential for Market Power in California's Electricity Industry. *Journal of Industrial Economics* 47, no. 3: 285-323.

Borenstein, Severin, James Bushnell, and Christopher Knittel. 1999. Market Power in Electricity Markets: Beyond Concentration Measures. *Energy Journal* 20, no. 4: 65-88.

Borenstein, Severin, James Bushnell, and Steven Stoft. 1998. The Competitive Effects of Transmission Capacity in a Deregulated Electricity Market. *Rand Journal of Economics*. Forthcoming.

Borenstein, Severin, James Bushnell, and Frank Wolak. 1999. *Diagnosing Market Power in California's Deregulated Wholesale Electricity Market*. POWER Working Paper PWP-064. University of California Energy Institute.

Bradley, P.S. and Usama M. Fayyad. 1998. Refining Initial Points for K-Means Clustering. In *Fifteenth International Conference on Machine Learning*. Madison, Wisconsin: Morgan Kaufmann Publishers.

Bushnell, James. 1998. *Water and Power: Hydroelectric Resources in the Era of Competition in the Western U.S.* POWER Working Paper PWP-056. University of California Energy Institute.

Cardell, Judith B., Carrie Cullen Hitt, and William W. Hogan. 1997. Market power and Strategic Interaction in Electricity Networks. *Resource and Energy Economics* 19: 109-137.

Chao, Hung-po and Stephen Peck. 1996. A Market Mechanism for Electric Power Transmission. *Journal of Regulatory Economics* 10: 25-59.

Cicchetti, Charles J. and Colin M. Long. 1999. Transmission Products and Pricing: Hidden Agendas in the ISO/Transco Debate. *Public Utilities Fortnightly* 137, no. 12: 33-45.

Colorado Air Quality Control Commission. 1999. *Colorado Air Quality Control Commission: Report to the Public 1998-1999*. Denver: Colorado Department of Public Health and Environment.

Colorado Electricity Advisory Panel. 1999. *Evaluation Study Report*. Denver: Colorado Public Utilities Commission.

Colorado Office of Consumer Counsel. 1999. *Comments of the OCC to the Colorado Electricity Advisory Panel on Market Power: The Potential Exercise of Horizontal Market Power in a Deregulated Colorado Electricity Market*. Denver: Colorado's Office of Consumer Counsel.

Colorado Public Utilities Commission. 2000. Decision No. C00-190, Docket No. 99A-549E. Denver: State of Colorado.

Deb, Rajat, Richard Albert, and Lie-Long Hsue. 1996. *Modeling Competitive Energy Market in California: Analysis of Restructuring*. Los Altos, Calif: LCG Consulting.

Energy Information Administration (EIA). 1996a. *Annual Energy Outlook 1997*. Washington, D.C.: U.S. Department of Energy.

1996b. *Electric Power Annual, Volume I*. Washington, D.C.: U.S. Department of Energy.

1998a. *The Changing Structure of the Electric Power Industry: Selected Issues, 1998*. Washington, D.C.: U.S. Department of Energy.

1998b. *Electric Power Annual, Volume I*. Washington, D.C.: U.S. Department of Energy.

2000. *Status of State Electric Utility Deregulation Activity*. Washington, D.C.: U.S. Department of Energy.

Federal Energy Regulatory Commission (FERC). 1981. *Power Pooling in the United States*. Washington, DC: Office of Electric Power Regulation.

1996. ORDER NO. 888, Docket No. RM95-8-000 and RM94-7-001. Washington, DC.

1999. Docket No. RM99-2-000, Regional Transmission Organizations. Washington, DC.

Feiler, Thomas, Karl R. Rabago, and Katherine Wang. 1999. *Socio-Economic and Legal Issues Related to an Evaluation of the Regulatory Structure of the Retail Electric Industry in the State of Colorado*. Econergy International Corporation.

Fox-Penner, Peter. 1998. *Electric Utility Restructuring: A Guide to the Competitive Era*. Vienna, Virginia: Public Utilities Reports, Inc.

Graves, Frank C., E. Grant Read, Philip Q. Hanser, and Robert L. Earle. 1998. One-Part Markets for Electric Power: Ensuring the Benefits of Competition. In *Power Systems Restructuring: Engineering and Economics*, ed. Marija Ilic, Francisco Galiana, and Lester Fink. Boston: Kluwer Academic Publishers.

Gray, H. M. 1940. The Passing of the Public Utility Concept. *Journal of Land and Public Utility Economics* (February).

Green, Richard J. and David M. Newbery. 1992. Competition in the British Electricity Spot Market. *Journal of Political Economy* 100, no. 5: 929-953.

Hebert, Jr., Curt L. and Joshua Z. Rokach. 1999. The FERC-State Dialogue on Electric Transmission: Where We Go from Here. *Public Utilities Fortnightly* 137, no. 9: 24-31.

Hobbs, Benjamin F. 1986. Network Models of Spatial Oligopoly with an Application to Deregulation of Electricity Generation. *Operations Research* 34, no. 3 (May-June): 395-409.

Hogan, William H. 1993. Markets in Real Electric Networks Require Reactive Prices. *The Energy Journal* 14, no. 3: 171-200.

\_\_\_\_\_. 1997. A Market Power Model with Strategic Interaction in Electricity Networks. *The Energy Journal* 18, no. 4: 107-141.

\_\_\_\_\_. 1998. *Competitive Electricity Market Design: A Wholesale Primer*. Cambridge, MA: Center for Business and Government, John F. Kennedy School of Government, Harvard University.

Hogan, William H., Grant Read, and Brendan J. Ring. 1996. Using Mathematical Programming for Electricity Spot Pricing. *International Transactions in Operational Research* 3, no. 3/4: 209-221.

Joskow, Paul L. 1995. *Horizontal Market Power in Wholesale Power Markets*. Draft.

Joskow, Paul L. and Richard Schmalensee. 1983. *Markets for Power: An Analysis of Electric Utility Deregulation*. Cambridge, Massachusetts: The MIT Press.

Jurewitz, John L. and Robin J. Walther. 1997. Must-Run Generation: Can We Mix Regulation and Competition Successfully? *The Electricity Journal* 10, no. 10: 61-70.

Kahn, Edward, Shawn Bailey, and Luis Pando. 1997. Simulating Electricity Restructuring in California: Interactions with the Regional Market. *Resource and Energy Economics* 19: 3-28.

Klemperer, Paul D. and Margaret A. Meyer. 1989. Supply Function Equilibria in Oligopoly under Uncertainty. *Econometrica* 57, no. November: 1243-77.

Michaels, Robert J. 1999. ISO or Transco? It's not the Profit, But Who Gets the Reward. *Public Utilities Fortnightly* 137, no. 15: 52-54.

Oren, S. 1997. Economic Inefficiency of Passive Transmission Rights in Congested Electricity System with Competitive Generation. *The Energy Journal* 18, no. 1: 12-26.

PJM Interconnection, L.L.C. 1998. *PJM Open Access Transmission Tariff*.

Public Service Company of Colorado. 1999. *Draft 1999 Integrated Resource Plan*.

Read, E. Grant and Brendan J. Ring. 1995. A Dispatch Based Pricing Model for the New Zealand Electricity Market. *Transmission Pricing*. Forthcoming.

Rose, Kenneth. 1999. Testimony Before the U.S. House of Representatives Committee on Commerce Subcommittee on Energy and Power "Electricity Competition: Market Power, Mergers, and PUHCA." Washington, D.C.: The National Regulatory Research Institute.

Rosen, Richard A. and Heidi L. Kroll. 1996. *"Leveraging": The Key to the Exercise of Market Power in a POOLCO*. Boston: Tellus Institute.

Rudkevich, Aleksandr, Max Duckworth, and Richard Rosen. 1998. Modeling Electricity Pricing in a Deregulated Generation Industry: The Potential for Oligopoly Pricing in a Poolco. *The Energy Journal* 19, no. 3: 19-48.

Schmalensee, Richard and Bennett W. Golub. 1984. Estimating Effective Concentration in Deregulated Wholesale Electricity Markets. *Rand Journal of Economics* 15, no. 1: 12-26.

Skinner, Laurence E. 1999. RTOs by 2002? The Transmission Revolution Won't Be Quick. *Public Utilities Fortnightly* 137, no. 15: 59-66.

Stoft, Steven. 1997. *The Effect of the Transmission Grid on Market Power*. LBNL Report #40479. Ernest Orlando Lawrence Berkeley National Laboratory.

—. 1999a. Financial Transmission Rights Meet Cournot: How TCCs Curb Market Power. *The Energy Journal* 20, no. 1: 1-23.

—. 1999b. *Using Game Theory to Study Market Power in Simple Networks*. IAEE Tutorial on Game Theory Applications to Power Systems.

Stone and Webster Management Consultants, Inc. 1999. *Energy and Economic Modeling Issues Related to an Evaluation of the Regulatory Structure of the Retail Electric Industry in the State of Colorado*. Englewood, Colo.: Colorado's Electric Advisory Panel.

Sweetser, Al. 1998a. An Empirical Analysis of a Dominant Firm's Market Power in a Restructured Electricity Market: A Case Study of Colorado. PhD Dissertation, Colorado School of Mines, Golden, Colo.

———. 1998b. Measuring Market Power in a State with a Dominant Supplier: A Case Study. *The Electricity Journal* (July): 61-70.

U.S. Department of Justice and Federal Trade Commission. 1992. Statement Accompanying Release of Revised Merger Guidelines.

Viscusi, W. Kip, John M. Vernon, and Joseph E. Harrington, Jr. 1998. *Economics of Regulation and Antitrust*. Cambridge, Massachusetts: The MIT Press.

Weiss, Jurgen. 1998a. *Congestion Rents and Oligopolistic Competition in Electricity Networks: An Experimental Investigation*. Cambridge, MA: Harvard Business School.

———. 1998b. *Market Power Issues in the Restructuring of the Electricity Industry: An Experimental Investigation*. Cambridge, MA: Harvard Business School.

Werden, Gregory J. 1996. Identifying Market Power in Electric Generation. *Public Utilities Fortnightly* February 15: 16-21.

Western Systems Coordinating Council (WSCC). 1998. *WSCC Operating Reserve White Paper*.

Wolak, Frank A. and Robert H. Patrick. 1996. *The Impact of Market Rules and Market Structure on the Price Determination Process in the England and Wales Electricity Market*. Stanford University.

Wolfram, Catherine D. 1995. *Measuring Duopoly Power in the British Electricity Spot Market*. Cambridge, MA: MIT Department of Economics.

## Appendix A

## GAMS CODE

```
$Title WSCC
$Offupper
$offlisting
$offsymxref
$offsymlist
option
      limrow = 0,
      limcol = 0,
      solprint = off,
      sysout = off,
      iterlim = 500000,
      reslim = 50000;
```

## Sets

```
i      plants /
$include plants.txt
```

```
/
```

```
j      regions /
$include regions.txt
```

```
/
```

```
l      companies /
$include companies.txt
/;
```

```
alias(j, k);
```

## Parameters

```
cap(i,j,l)      capacity of plant i in region j /
$include capacities.txt
```

cost(i,j,l) variable cost of plant i in region j /  
\$include costs.txt

mx(i,j,l) forced outage rate of plant i in region j /  
\$include for.txt

dem(j) demand in region j /  
\$include demand.txt

tcap(j,k) transmission capacity for line k /  
\$include tcap.txt

bestp(j)  
besty(j,k);

#### Scalars

\$include scalars.txt

EMAX  
WMAX  
NEMAX  
BESTPROFIT  
BESTECO  
BESTWCO  
BESTNE  
PROFIT  
TOTE  
TOTW  
TOTNE  
LIMIT  
DONE0  
DONE  
DONE1  
DONE2  
VARY\_TRANS

INCREMENT  
 PCTOT  
 PCPERC  
 TEMPDP;

### Variables

$x(i,j,l)$  how much plant i in region j generates  
 $xr(i,j,l)$  how much plant i in region j has in reserve  
 $y(j,k)$  how much of generation in region j is used in region k  
 $z$  total generation cost ;

### Positive Variables x, xr,y ;

$y.up(j,k) = TCAP(j,k);$   
 $EMAX = \text{sum}(i, \text{cap}(i, "ECO", "PSCo") * (1 - mx(i, "ECO", "PSCo")));$   
 $WMAX = \text{sum}(i, \text{cap}(i, "WCO", "PSCo") * (1 - mx(i, "WCO", "PSCo")));$   
 $NEMAX = \text{sum}(i, \text{cap}(i, "NE", "PSCo") * (1 - mx(i, "NE", "PSCo")));$

### Equations

totcost define objective function  
 $\text{capacity}(i,j,l)$  observe supply limit at plant i  
 $\text{demand}(j)$  demand in region k  
 $\text{reserve}(l)$  reserve requirement  
 $\text{psc}oe$  total production by PSCo  
 $\text{psc}ow$   
 $\text{psc}one$  ;

totcost ..  $z = e = \text{sum}((i,j,l), COST(i,j,l) * x(i,j,l))$  ;

$\text{capacity}(i,j,l) . x(i,j,l) + xr(i,j,l) = l = CAP(i,j,l) * (1 - mx(i,j,l))$  ;

$\text{demand}(j) .. \text{sum}((i,l), x(i,j,l) * (1 - loss)) + \text{sum}(k, y(k,j) * (1 - tloss)) - \text{sum}(k, y(j,k)) = e = \text{demperc} * DEM(j)$  ;

$\text{reserve}(l) .. \text{sum}((i,j), xr(i,j,l) - res\_ratio * x(i,j,l)) = g = 0$ ;

$\text{psc}oe .. \text{sum}(i, x(i, "ECO", "PSCo")) = e = TOTE$ ;

$\text{psc}ow .. \text{sum}(i, x(i, "WCO", "PSCo")) = e = TOTW$ ;

```

pscone ..      sum(i, x(i,"NE","PSCo")) =e= TOTNE;

Model pc / totcost, capacity, demand, reserve /
      impc /all/;

file results /results.csv/
      pc_results /pc_results.csv/
      impc_res /impc_res.csv/
      pc_trans /pc_trans.csv/
      impc_tra /impc_tra.csv/
      pc_price /pc_price.csv/
      impc_p /impc_p.csv/
      trans /trans.csv/;

results.pc = 5;
results.nd = 3;
pc_results.pc = 5;
pc_results.nd = 3;
impc_res.pc = 5;
impc_res.nd = 3;
pc_trans.pc = 5;
pc_trans.nd = 3;
pc_trans.pw = 400;
impc_tra.pc = 5;
impc_tra.nd = 3;
impc_tra.pw = 400;
pc_price.pc = 5;
pc_price.nd = 3;
impc_p.pc = 5;
impc_p.nd = 3;
trans.pc = 5;
trans.nd = 3;

```

- \* The following block of code was provided by Steve Dirkse of GAMS
 

```

parameter RCAP(I,J,L);
RCAP(I,J,L) = CAP(i,j,l)*(1-mx(i,j,l));
x.fx(I,J,L)$RCAP(I,J,L) eq 0) = 0;
xr.fx(I,J,L)$RCAP(I,J,L) eq 0) = 0;
pc.holdfixed = 1;
```

```

impc.holdfixed = 1;

PCPERC = .5;
TEMPDP = demperc;
VARY_TRANS = 0;
INCREMENT = 100;
DONE0 = 0;
while (DONE0 = 0 and tcap("WCO","ECO") < 2700,
      * Sets initial iteration at 100% when varying demand
      if (vary_dem > 0,
          demperc = 1;
      );
      * Sets initial iteration at 100% when varying demand
      * Demand Looop
      while (demperc ge .45,
            Solve pc using lp minimizing z ;
            PROFIT = sum((i,j), (demand.m(j) - COST(i,j,"PSCo"))*x.l(i,j,"PSCo"));
            TOTE = sum(i, x.l(i,"ECO","PSCo"));
            TOTW = sum(i, x.l(i,"WCO","PSCo"));
            TOTNE = sum(i, x.l(i,"NE","PSCo"));
            PCTOT = TOTE + TOTW + TOTNE;
            BESTPROFIT = PROFIT;
            BESTECO = TOTE;
            BESTWCO = TOTW;
            BESTNE = TOTNE;
            loop(j, bestp(j) = demand.m(j));
            loop(j, loop(k, besty(j,k) = y.l(j,k)));
            put pc_results ;
            put demperc, TOTE, TOTW, TOTNE, PROFIT, demand.m("ECO"),
            demand.m("WCO"), demand.m("NE"), y.l("WCO","ECO"),
            y.l("NE","ECO"), y.l("ECO","WCO"), y.l("ECO","NE");
            put pc_price ;
            put demperc;
            loop(j, put demand.m(j));
            put /;

```

```

put pc_trans ;
    put demperc;
    loop(j, loop(k,
        if(tcap(j,k) > 0,
            put y.l(j,k)));
    );
    put /;
put results ;
    put demperc, TOTE, TOTW, TOTNE, PROFIT, demand.m("ECO"),
    demand.m("WCO"), demand.m("NE"), y.l("WCO","ECO"),
    y.l("NE","ECO"), y.l("ECO","WCO"), y.l("ECO","NE")/;
if (VARY_TRANS = 1,
    put trans ;
        put demperc, tcap("WCO","ECO"), PROFIT, demand.m("ECO"),
        y.l("WCO","ECO"), TOTE;
);

```

\*

Allows IMPC algorithm to run

```

if (Run_model = 1,
    TOTE = EMAX;
    DONE = 0;
    while (DONE = 0 and TOTE ge 0,
        TOTW = WMAX;
        DONE1 = 0;
        while (DONE1 = 0 and TOTW >= 0,
            TOTNE = NEMAX;
            DONE2 = 0;
            LIMIT = 0;
            while (LIMIT = 0 and DONE2 = 0 and TOTNE >= 0 and
                TOTNE + TOTW + TOTE >= PCPERC*PCTOT,
                Solve impc using lp minimizing z ;
                if (impc.modelstat = 1,
                    LIMIT = sum((i,j), x.l(i,j,"limit"));
                    PROFIT = sum((i,j), (demand.m(j) -
                    COST(i,j,"PSCo"))*x.l(i,j,"PSCo")));

```

\*

Stores new best solution

```

if (PROFIT > BESTPROFIT,
    BESTPROFIT = PROFIT;
)
```

```

        BESTECO = TOTE;
        BESTWCO = TOTW;
        BESTNE = TOTNE;
        loop(j, bestp(j) = demand.m(j));
        loop(j, loop(k, besty(j,k) = y.l(j,k)));
    );

    * Stores new best solution
    put results ;
    put demperc, TOTE, TOTW,
    TOTNE, PROFIT,
    demand.m("ECO"),
    demand.m("WCO"),
    demand.m("NE"),
    y.l("WCO","ECO"),
    y.l("NE","ECO"),
    y.l("ECO","WCO"),
    y.l("ECO","NE");
    if (TOTNE = 0,
        DONE2 = 1;
    elseif (LIMIT = 0),
        TOTNE = TOTNE -
        prod_delta;
        if (TOTNE < 0,
            TOTNE = 0;
        );
    );
    else
        DONE2 = 1;
    );
    );
    if (TOTW = 0,
        DONE1 = 1;
    elseif (LIMIT > 0 and TOTNE = NEMAX),
        DONE1 = 1;
    else
        TOTW = TOTW - prod_delta;

```

```

if(TOTW < 0,
    TOTW = 0;
);
);

if(TOTE = 0,
    DONE = 1;
elseif(LIMIT > 0 and TOTW = WMAX),
    DONE = 1;
else
    TOTE = TOTE - prod_delta;
    if(TOTE < 0,
        TOTE = 0;
    );
);
);

* ECO Loop
put impc_res ;
    put demperc, BESTECO, BESTWCO, BESTNE, BESTPROFIT,
    bestp("ECO"), bestp("WCO"), bestp("NE"), besty("WCO",
    "ECO"), besty("NE", "ECO"), besty("ECO", "WCO"),
    besty("ECO", "NE")/;
put impc_p ;
    put demperc;
    loop(j, put bestp(j));
    put '/';
put impc_tra ;
    put demperc;
    loop(j, loop(k,
        if(tcap(j,k) > 0,
            put besty(j,k)));
    );
    put '/';
if(VARY_TRANS = 1,
    put trans ;
)

```

```
        put BESTPROFIT, bestp("ECO"), besty("WCO","ECO"),
        BESTECO/;
    );
}

*           Allows IMPC algorithm to run
*           Decreases demand for next iteration
if (vary_dem = 1,
    demperc = demperc - 0.09;
elseif (vary_dem = 2),
    demperc = demperc - 0.0455;
else
    demperc = demperc - 1;
);

*           Decreases demand for next iteration
);

*           Demand Loop

if (VARY_TRANS = 1,
    TCAP("WCO","ECO") = TCAP("WCO","ECO") + INCREMENT;
    y.up("WCO","ECO") = TCAP("WCO","ECO");
    demperc = TEMPDP;
else
    DONE0 = 1;
);
);
```

Appendix B  
WSCC DATABASE

PlantID	Plant Name	Company	Region	Capacity (MW)	VC (\$/MWh)	FOR
p1	az1	az_gen	az	1295	0.00	0.0000
p2	az2	az_gen	az	10919	15.56	0.0474
p3	az3	az_gen	az	2233	23.77	0.0511
p4	az4	az_gen	az	1309	31.91	0.0482
p5	az5	az_gen	az	762	36.57	0.0690
p6	az6	az_gen	az	273.5	44.25	0.0786
p7	az7	az_gen	az	201	46.29	0.0797
p8	az8	az_gen	az	49.2	48.15	0.0797
p9	az9	az_gen	az	67	50.64	0.0797
p10	az10	az_gen	az	16	82.91	0.0797
p1	az11	INTLD	az	650	191.56	0.0000
p1	Limit	limit	az	100	200.00	0.0000
p1	can1	can_gen	can	12079	0.00	0.0000
p2	can2	can_gen	can	5448	4.42	0.0359
p3	can3	can_gen	can	3811	15.45	0.0336
p4	can4	can_gen	can	2173	22.93	0.0393
p5	can5	can_gen	can	104.5	29.73	0.0431
p6	can6	can_gen	can	36.5	32.15	0.0260
p7	can7	can_gen	can	20	52.55	0.0010
p8	can8	can_gen	can	31	57.54	0.0500
p9	can9	can_gen	can	5	67.54	0.0268
p10	can10	can_gen	can	94	69.96	0.0797
p1	can11	INTLD	can	362	191.56	0.0000
p1	Limit	limit	can	100	200.00	0.0000
p1	Manitou	CSU	eco	5	0.00	0.0000
p2	Ruxton	CSU	eco	1	0.00	0.0000
p3	Tesla	CSU	eco	25	0.00	0.0000
p4	Nixon	CSU	eco	208	12.93	0.0654
p5	Ray D Nixon CC	CSU	eco	400	20.33	0.0450
p6	Drake	CSU	eco	133	21.54	0.0628

PlantID	Plant Name	Company	Region	Capacity (MW)	VC (\$/MWh)	FOR
p7	Drake	CSU	eco	79	23.31	0.0508
p8	Drake	CSU	eco	47	23.63	0.0508
p9	Ray D Nixon GT	CSU	eco	80	29.78	0.0400
p10	Birdsall	CSU	eco	56	36.13	0.0417
p11	Drake	CSU	eco	11	39.46	0.0417
p12	Drake	CSU	eco	5	41.24	0.0417
p13	SECC	CSU	eco	2	78.78	0.0268
p1	Dillion Dam	fringe	eco	2	0.00	0.0000
p2	Foothills Hydro	fringe	eco	2	0.00	0.0000
p3	JB Hydro	fringe	eco	0	0.00	0.0000
p4	Redlands	fringe	eco	1.6	0.00	0.0000
p5	Roberts Tunnel	fringe	eco	6	0.00	0.0000
p6	Strontia Springs	fringe	eco	1	0.00	0.0000
p7	Vallencito Hydro	fringe	eco	5	0.00	0.0000
p8	Raton	fringe	eco	12	14.11	0.0508
p9	Greeley Energy	fringe	eco	72	23.14	0.0460
p10	Wattenberg Field	fringe	eco	1	27.42	0.0460
p11	Biogas	fringe	eco	5	28.05	0.0500
p12	Westlock	fringe	eco	17	28.05	0.0500
p13	Lamar	fringe	eco	25	33.49	0.0417
p14	Trinidad	fringe	eco	10	38.95	0.0610
p15	Bullock	fringe	eco	12	47.63	0.0417
p16	Springfield 1-2, 4-5	fringe	eco	4	65.45	0.0268
p17	La Junta	fringe	eco	15	71.89	0.0268
p18	Holly	fringe	eco	2.5	79.81	0.0268
p19	Holly	fringe	eco	2.5	84.43	0.0268
p20	Las Animas	fringe	eco	7	92.87	0.0268
p1	GenCC_Colorado	GenUtility	eco	235	20.33	0.0200
p2	GenGT_Colorado	GenUtility	eco	150	29.78	0.0200
p1	INTLD PSC	INTLD	eco	142	191.56	0.0000
p1	Limit	limit	eco	100	200.00	0.0000
p1	Idlywilde	PRPA	eco	1	0.00	0.0000
p2	Longmont	PRPA	eco	0.6	0.00	0.0000
p3	Rawhide	PRPA	eco	269	8.70	0.0654
p1	Ames	PSCo	eco	3.8	0.00	0.0000
p2	Betasso Hydro	PSCo	eco	3	0.00	0.0000
p3	Boulder Hydro	PSCo	eco	20	0.00	0.0000

PlantID	Plant Name	Company	Region	Capacity (MW)	VC (\$/MWh)	FOR
p4	Bridal Veil Falls	PSCo	eco	1	0.00	0.0000
p5	Georgetown Hydro	PSCo	eco	1.6	0.00	0.0000
p6	Hillcrest	PSCo	eco	1	0.00	0.0000
p7	Kohler Hydro	PSCo	eco	0	0.00	0.0000
p8	Lakewood Hydro	PSCo	eco	3	0.00	0.0000
p9	Maxwell Hydro	PSCo	eco	0	0.00	0.0000
p10	Orodel Hydro	PSCo	eco	0	0.00	0.0000
p11	Ouray	PSCo	eco	0.5	0.00	0.0000
p12	Palisade Hydro	PSCo	eco	3.2	0.00	0.0000
p13	Salida 1	PSCo	eco	0.8	0.00	0.0000
p14	Salida 2	PSCo	eco	0.6	0.00	0.0000
p15	Silver Lake CO	PSCo	eco	2	0.00	0.0000
p16	Stagecoach Hydro	PSCo	eco	1	0.00	0.0000
p17	Sunshine Hydro	PSCo	eco	1	0.00	0.0000
p18	Cabin Creek	PSCo	eco	324	1.43	0.0000
p19	Pawnee	PSCo	eco	511	11.06	0.0824
p20	Comanche	PSCo	eco	335	11.12	0.0846
p21	Comanche	PSCo	eco	325	11.29	0.0846
p22	Arapahoe	PSCo	eco	111	11.39	0.0628
p23	Cherokee	PSCo	eco	352	11.56	0.0846
p24	Cherokee	PSCo	eco	106.5	12.04	0.0628
p25	Cherokee	PSCo	eco	158	12.09	0.0628
p26	Arapahoe	PSCo	eco	45	12.33	0.0508
p27	Arapahoe	PSCo	eco	0	12.36	0.0508
p28	Cherokee	PSCo	eco	106	12.43	0.0628
p29	Arapahoe	PSCo	eco	0	12.44	0.0508
p30	Cameo	PSCo	eco	49	12.89	0.0508
p31	Cameo	PSCo	eco	24	14.59	0.0508
p32	Valmont	PSCo	eco	189	15.42	0.0628
p33	Ft St Vrain CC	PSCo	eco	728	20.33	0.0460
p34	Thrm Ft Lupton	PSCo	eco	32	24.29	0.0460
p35	Brush Cogen Part	PSCo	eco	68	27.42	0.0460
p36	Colo Power Partn	PSCo	eco	50	27.42	0.0460
p37	Coors Biotech CG	PSCo	eco	3	27.42	0.0460
p38	Thermo Carbonic	PSCo	eco	150	27.42	0.0460
p39	Thermo Indust	PSCo	eco	122	27.42	0.0460
p40	Univ. CO Cogen	PSCo	eco	10	27.42	0.0460

PlantID	Plant Name	Company	Region	Capacity (MW)	VC (\$/MWh)	FOR
p41	BIV Generation/Brush 4	PSCo	eco	50	35.00	0.0000
p42	Colo Power Partn/Brush	PSCo	eco	25	35.00	0.0000
p43	Customer Cogen	PSCo	eco	32	35.00	0.0000
p44	FREA/Front Range	PSCo	eco	148	35.00	0.0000
p45	Fulton Cogen	PSCo	eco	214	35.00	0.0000
p46	Valmont/Arapahoe Contingency	PSCo	eco	108	35.00	0.0000
p47	Valmont	PSCo	eco	53	36.56	0.0797
p48	Zuni	PSCo	eco	68	37.03	0.0417
p49	Zuni	PSCo	eco	39	37.52	0.0417
p50	Alamosa GT	PSCo	eco	18	41.31	0.0797
p51	Ft. Lupton GT	PSCo	eco	50	41.54	0.0797
p52	Alamosa GT	PSCo	eco	18	43.89	0.0797
p53	Cherkee Dies	PSCo	eco	5	79.92	0.0268
p1	Burlington WSCC	TSGT	eco	60	63.85	0.0797
p1	Big Thompson	WAPA	eco	4.6	0.00	0.0000
p2	Estes	WAPA	eco	45	0.00	0.0000
p3	Flatiron	WAPA	eco	94.5	0.00	0.0000
p4	Green Mountain	WAPA	eco	26	0.00	0.0000
p5	Marys Lake	WAPA	eco	8.1	0.00	0.0000
p6	Pole Hill	WAPA	eco	38.2	0.00	0.0000
p7	Rocky	WAPA	eco	8	26.88	0.0417
p1	W.N. Clark	WEPL	eco	41	13.75	0.0508
p2	Pueblo	WEPL	eco	20	29.09	0.0417
p3	WPE Diesel	WEPL	eco	10	67.54	0.0268
p1	fc1	fc_gen	fc	10	0.00	0.0000
p2	fc2	fc_gen	fc	1480	12.42	0.0658
p3	fc3	fc_gen	fc	1650	13.71	0.0655
p4	fc4	fc_gen	fc	220	14.02	0.0654
p5	fc5	fc_gen	fc	170	14.99	0.0628
p6	fc6	fc_gen	fc	220	15.31	0.0654
p7	fc7	fc_gen	fc	498	21.67	0.0846
p8	fc8	fc_gen	fc	316	23.29	0.0846
p9	fc9	fc_gen	fc	488	25.15	0.0846
p10	fc10	fc_gen	fc	312	26.29	0.0846
p1	Limit	limit	fc	100	200.00	0.0000
p1	ncall11	INTLD	ncal	200	127.71	0.0000

PlantID	Plant Name	Company	Region	Capacity (MW)	VC (\$/MWh)	FOR
p2	ncal12	INTLD	ncal	1132	191.56	0.0000
p1	Limit	limit	ncal	100	200.00	0.0000
p1	ncal1	ncal_gen	ncal	9011.1	0.12	0.0000
p2	ncal2	ncal_gen	ncal	147.7	8.03	0.0000
p3	ncal3	ncal_gen	ncal	163.6	13.46	0.0284
p4	ncal4	ncal_gen	ncal	629.3	18.29	0.0497
p5	ncal5	ncal_gen	ncal	3627.8	26.34	0.0146
p6	ncal6	ncal_gen	ncal	11284	31.32	0.0123
p7	ncal7	ncal_gen	ncal	2834.16	39.76	0.0764
p8	ncal8	ncal_gen	ncal	900.6	53.54	0.0775
p9	ncal9	ncal_gen	ncal	291.7	67.87	0.0461
p10	ncal10	ncal_gen	ncal	274	72.99	0.0800
p1	Neil Simpson	BHPL	ne	19	9.92	0.0508
p2	Neil Simpson	BHPL	ne	80	10.42	0.0508
p3	Ben French BHPL	BHPL	ne	22	12.86	0.0508
p4	Osage	BHPL	ne	10	14.24	0.0508
p5	Osage	BHPL	ne	10	14.51	0.0508
p6	Osage	BHPL	ne	10	14.55	0.0508
p7	Ben French IC	BHPL	ne	10	57.30	0.0268
p8	Ben French GT	BHPL	ne	25	73.68	0.0797
p9	Ben French GT	BHPL	ne	25	74.35	0.0797
p1	Foote Creek	fringe	ne	20	28.05	0.0500
p1	GenCC_Wyoming	GenUtility	ne	235	18.86	0.0200
p2	GenGT_Wyoming	GenUtility	ne	150	27.51	0.0200
p1	Limit	limit	ne	100	200.00	0.0000
p1	Johnston	PAC	ne	330	8.05	0.0846
p2	Johnston	PAC	ne	106	8.11	0.0628
p3	Johnston	PAC	ne	230	8.18	0.0654
p4	Johnston	PAC	ne	106	8.31	0.0628
p5	Wyodak	PAC	ne	320	10.77	0.0846
p6	J Bridger	PAC	ne	520	12.84	0.0824
p7	GenChem	PAC	ne	32	28.57	0.0500
p8	Cheynne Dies	PAC	ne	10	67.54	0.0268
p1	Laramie River	PSCo	ne	175	7.03	0.0824
p1	Alcova	WAPA	ne	36	0.00	0.0000
p2	Boysen	WAPA	ne	15	0.00	0.0000
p3	Buffalo Bill	WAPA	ne	18	0.00	0.0000

PlantID	Plant Name	Company	Region	Capacity (MW)	VC (\$/MWh)	FOR
p4	Flaming Gorge	WAPA	ne	152	0.00	0.0000
p5	Fontenelle	WAPA	ne	10	0.00	0.0000
p6	Fremont Canyon	WAPA	ne	66.8	0.00	0.0000
p7	Garland Canal Project	WAPA	ne	0	0.00	0.0000
p8	Glendo	WAPA	ne	39	0.00	0.0000
p9	Guernsey	WAPA	ne	6.4	0.00	0.0000
p10	Heart Mountain	WAPA	ne	5.1	0.00	0.0000
p11	Kortes	WAPA	ne	36	0.00	0.0000
p12	Pilot Butte	WAPA	ne	1.6	0.00	0.0000
p13	Reudi	WAPA	ne	4	0.00	0.0000
p14	Seminoe	WAPA	ne	51	0.00	0.0000
p15	Shoshone	WAPA	ne	5	0.00	0.0000
p16	Spirit Mountain	WAPA	ne	4.5	0.00	0.0000
p17	Yellowtail	WAPA	ne	250	0.00	0.0000
p18	Laramie River	WAPA	ne	550	6.79	0.0824
p19	Laramie River	WAPA	ne	375	7.03	0.0824
p20	MEAN	WAPA	ne	19.6	49.59	0.0610
p1	Limit	limit	nm	100	200.00	0.0000
p1	nm1	nm_gen	nm	73.1	0.00	0.0000
p2	nm2	nm_gen	nm	235	18.02	0.0654
p3	nm3	nm_gen	nm	567	22.20	0.0293
p4	nm4	nm_gen	nm	26	24.39	0.0460
p5	nm5	nm_gen	nm	374	30.49	0.0554
p6	nm6	nm_gen	nm	712.6	32.90	0.0368
p7	nm7	nm_gen	nm	16	38.71	0.0417
p8	nm8	nm_gen	nm	14	40.11	0.0447
p9	nm9	nm_gen	nm	51.3	44.57	0.0417
p10	nm10	nm_gen	nm	91	50.40	0.0797
p1	Limit	limit	nw	100	200.00	0.0000
p1	nw1	nw_gen	nw	33138.3	0.00	0.0000
p2	nw2	nw_gen	nw	189.5	5.82	0.0500
p3	nw3	nw_gen	nw	207	7.76	0.0599
p4	nw4	nw_gen	nw	4184	10.58	0.0715
p5	nw5	nw_gen	nw	1170	13.33	0.0000
p6	nw6	nw_gen	nw	533	15.29	0.0824
p7	nw7	nw_gen	nw	2577	17.88	0.0505
p8	nw8	nw_gen	nw	2196	22.66	0.0500

PlantID	Plant Name	Company	Region	Capacity (MW)	VC (\$/MWh)	FOR
p9	nw9	nw_gen	nw	685	27.10	0.0455
p10	nw10	nw_gen	nw	150	35.74	0.0200
p11	nw11	nw_gen	nw	88	48.84	0.0500
p12	nw12	nw_gen	nw	4	61.58	0.0268
p13	nw13	nw_gen	nw	88	66.10	0.1135
p14	nw14	nw_gen	nw	70	72.56	0.0774
p15	nw15	nw_gen	nw	29	75.68	0.0797
p1	Limit	limit	scal	100	200.00	0.0000
p1	scal1	scal_gen	scal	2154.4	0.00	0.0000
p2	scal2	scal_gen	scal	400	3.30	0.0000
p3	scal3	scal_gen	scal	588.1	8.03	0.0000
p4	scal4	scal_gen	scal	87	11.73	0.0484
p5	scal5	scal_gen	scal	4663.6	14.05	0.0032
p6	scal6	scal_gen	scal	285.8	17.98	0.0529
p7	scal7	scal_gen	scal	209.6	23.93	0.0200
p8	scal8	scal_gen	scal	5923.79	27.90	0.0416
p9	scal9	scal_gen	scal	12678.5	32.98	0.0222
p10	scal10	scal_gen	scal	5669.2	39.31	0.0710
p11	scal11	scal_gen	scal	197	48.09	0.0424
p12	scal12	scal_gen	scal	108	51.23	0.0428
p13	scal13	scal_gen	scal	287	53.00	0.0500
p14	scal14	scal_gen	scal	46.4	55.27	0.0797
p15	scal15	scal_gen	scal	39	56.96	0.0968
p16	scal16	scal_gen	scal	45	58.50	0.0934
p17	scal17	scal_gen	scal	441	61.24	0.0730
p18	scal18	scal_gen	scal	163	64.92	0.0739
p19	scal19	scal_gen	scal	266.5	69.96	0.0708
p20	scal20	scal_gen	scal	66	76.69	0.0797
p21	scal21	scal_gen	scal	19	78.68	0.0969
p22	scal22	scal_gen	scal	19	84.00	0.0969
p23	scal23	scal_gen	scal	166	86.17	0.0222
p24	scal24	scal_gen	scal	69	89.54	0.0773
p25	scal25	scal_gen	scal	142	117.80	0.0714
p1	scal26	INTLD	snev	1694	191.56	0.0000
p2	snev11	INTLD	snev	220	191.56	0.0000
p1	Limit	limit	snev	100	200.00	0.0000
p1	snev1	snev_gen	snev	2448.8	0.00	0.0000

PlantID	Plant Name	Company	Region	Capacity (MW)	VC (\$MWh)	FOR
p2	snev2	snev_gen	snev	595	14.89	0.0640
p3	snev3	snev_gen	snev	1385	17.14	0.0650
p4	snev4	snev_gen	snev	985	22.54	0.0327
p5	snev5	snev_gen	snev	243	23.37	0.0460
p6	snev6	snev_gen	snev	220	30.59	0.0460
p7	snev7	snev_gen	snev	80	31.41	0.0417
p8	snev8	snev_gen	snev	371	33.11	0.0485
p9	snev9	snev_gen	snev	182	35.20	0.0563
p10	snev10	snev_gen	snev	213	42.61	0.0797
p1	ut11	INTLTD	ut	520	191.56	0.0000
p1	Limit	limit	ut	100	200.00	0.0000
p1	ut1	ut_gen	ut	2496.3	0.00	0.0000
p2	ut2	ut_gen	ut	4171	10.86	0.0815
p3	ut3	ut_gen	ut	2921	19.47	0.0556
p4	ut4	ut_gen	ut	1319	28.97	0.0461
p5	ut5	ut_gen	ut	23	47.56	0.0500
p6	ut6	ut_gen	ut	101	53.00	0.0500
p7	ut7	ut_gen	ut	70	65.13	0.0327
p8	ut8	ut_gen	ut	6	72.06	0.0268
p9	ut9	ut_gen	ut	21	77.80	0.0268
p10	ut10	ut_gen	ut	34	90.65	0.0692
p1	Mt Elbert Condui	fringe	wco	3	0.00	0.0000
p2	American Atlas	fringe	wco	85	27.42	0.0460
p3	Ignacio Gas Plnt	fringe	wco	6	27.42	0.0460
p1	INTLTD TSGTW	INTLTD	wco	150	191.56	0.0000
p1	Limit	limit	wco	100	200.00	0.0000
p1	Shoshone Hydro	PSCo	wco	15	0.00	0.0000
p2	Tacoma	PSCo	wco	8.5	0.00	0.0000
p3	Craig	PSCo	wco	401	14.24	0.0846
p4	Fruita GT	PSCo	wco	20	43.25	0.0797
p1	Blue Valley Hydro	TSGT	wco	0	0.00	0.0000
p2	Craig	TSGT	wco	7	14.24	0.0846
p3	Nucla	TSGT	wco	76	19.01	0.0508
p4	Delta 1-7	TSGT	wco	8	30.78	0.0610
p1	Blue Mesa	WAPA	wco	86.4	0.00	0.0000
p2	Crystal	WAPA	wco	31	0.00	0.0000
p3	Lower Molina	WAPA	wco	4.9	0.00	0.0000

PlantID	Plant Name	Company	Region	Capacity (MW)	VC (\$/MWh)	FOR
p4	McPhee	WAPA	wco	1.3	0.00	0.0000
p5	Morrow Point	WAPA	wco	173.3	0.00	0.0000
p6	Mt. Elbert PS	WAPA	wco	200	0.00	0.0000
p7	Towaoc	WAPA	wco	11.5	0.00	0.0000
p8	Upper Molina	WAPA	wco	8.6	0.00	0.0000
p9	Williams Fork	WAPA	wco	3	0.00	0.0000
p10	Hayden	WAPA	wco	446	12.54	0.0641
p11	Craig	WAPA	wco	428	14.18	0.0846
p12	Craig	WAPA	wco	428	14.28	0.0846